A8630-3-U 9/89

1989 RELIABILITY ASSESSMENT

THE FUTURE OF BULK ELECTRIC SYSTEM RELIABILITY IN NORTH AMERICA 1989–1998

North American Electric Reliability Council

September 1989

Copyright © 1989 by North American Electric Reliability Council. All rights reserved.

FOREWORD

ABOUT THE COUNCIL

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to coordinate, promote, and communicate about the RELIABILITY of their generation and transmission systems. NERC is comprised of nine Regional Reliability Councils and one Affiliate encompassing virtually all of the electric utility systems in the United States, Canada, and the northern portion of Baja California, Mexico.

NERC is governed by a 27 member Board of Trustees — two utility executives from each Regional Reliability Council plus others to assure at least one representative from Canada and two from each segment of the industry: investor-owned, federal, rural electric cooperative, and state/municpal electric systems.

Meetings of the Board are attended by observers from the U.S. Department of Energy, the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Edison Electric Institute, the American Public Power Association, the National Rural Electric Cooperative Association, the Canadian Electrical Association, and the Electric Power Research Institute.

NERC's strength lies in its ability to call upon unmatched electric utility expertise and experience from member systems. Its technical activities are conducted by its Operating and Engineering Committees and their subgroups comprised of managerial and technical representatives from the Regions. The NERC staff, located in Princeton, New Jersey, provides project coordination and support for the Council's activities.

ABOUT THIS REPORT

The NERC Board of Trustees created the Reliability Assessment Subcommittee in 1970 to annually review the overall reliability of the existing and planned generation and transmission systems of the nine Regional Reliability Councils.

This 1989 Reliability Assessment report presents:

- *An assessment of electric generation and transmission reliabiltiy through 1998,*
- *A discussion of the key factors and issues affecting the reliability of future electric supply, and*
- *Detailed regional assessments of electric supply reliability, including reliability issues of specific regional concern.*

In preparing this report, the RAS interviewed representatives of selected Regions and reviewed detailed self-assessments prepared by each Region, including aggregate forecasts of peak demand and planned capacity resources. The RAS appraised regional plans for future electric generation and transmission facilities, and assessed the potential effect of legislation, regulations, and governmental policies on future electric supply reliability. This report is the culmination of these efforts and reflects the expertise, judgment, and interpretations of the RAS members.

Unless otherwise noted, the data presented in the figures and tables reflects conditions as of January 1, 1989. Data has been extracted from the April 1, 1989 Coordinated Bulk Power Supply Program (IE-411) Reports submitted to the U.S. Department of Energy by each Regional Reliability Council and from regional data submittals made directly to NERC. Detailed background information on projected peak demands, annual energy requirements, generating capabilities, transmission, and fossil fuel requirements are presented in a companion NERC report — "1989 Electricity Supply & Demand for 1989-1998."

1989 RELIABILITY ASSESSMENT

TABLE OF CONTENTS

Executive Summary 4

Reliability and What It Means to the Customer 6

Peak Demand Projections 9

Generation Reliability Assessment 14

Transmission Reliability Assessment 26

Reliability Issues

Demand Exceeding Forecast 33

Economy Versus Reliability 36

Public Policy Disincentives 38

Transmission Service and Deregulation 40

Environmental Considerations 43

Non-Utility Generation 46

Regional Assessments 50

ECAR — East Central Area Reliability Coordination Agreement 53

ERCOT — Electric Reliability Council of Texas 56

MAAC — Mid-Atlantic Area Council 59

MAIN — Mid-America Interconnected Network 63

MAPP — Mid-Continent Area Power Pool 67

NPCC — Northeast Power Coordinating Council 70

SERC — Southeastern Electric Reliability Council 75

SPP — Southwest Power Pool 79

WSCC — Western Systems Coordinating Council 82

EXECUTIVE SUMMARY

A reliable supply of electricity is essential to the economic well-being and security of the United States and Canada. While aggregate utility plans will support the forecast growth in peak demand, this report identifies a widespread trend of actual peak demands consistently exceeding forecasts. If this trend continues, supply deficiencies are likely by the early 1990s in the eastern half of the United States and Canada.

Several geographic areas are also identified where electric system reliability is at serious risk. Emergency operating measures, including controlled interruptions of customers' supply, will become more widespread in these areas.

Key issues and threats to reliability discussed in the report are:

Economy versus Reliability – Short-term economic goals continue to infringe on bulk electric system reliability.

Disincentives – Financial risks associated with uncertain regulatory policy are discouraging electric utilities from committing to needed additional generating capacity and transmission lines. Changing and conflicting federal, state or provincial, and local policies continue to delay the construction of critical generation and transmission facilities. These policies may ultimately erode the reliability of electric supply.

Use of Transmission Systems – Transmission systems are not planned and constructed for unlimited electricity transfers. The use of the bulk electric transmission networks to transfer electricity must be properly planned, scheduled, and controlled to maintain reliability.

Environmental Policy – Both new and existing generating capacity and transmission lines will be affected by environmental policies. Sound technical evaluations of the potential effects of proposed legislation on the environment and on electric system reliability are needed.

Non-Utility Generation – Many electric utilities are depending on non-utility generators to help supply a portion of their generating capacity. These generating units must be designed and operated to the same technical requirements as utility generators to assure their dependability and reliability over the longer term.

Specific regional reliability concerns identified in this assessment are:

ECAR – Acid rain legislation, when fully implemented, could cause the utilities in this Region to lose over 9,000 megawatts of generating capacity. This capacity would have to be replaced to maintain reliability.

ERCOT – Construction of several critical 345 kV transmission lines has been blocked resulting in inadequate transmission in the Region.

MAAC – For six consecutive years through 1988, this Region has experienced all-time record summer peak demands that have exceeded its forecast. Voltage reductions and frequent use of load management were employed to help limit peak demands during the 1988 summer. Capacity additions beyond those already planned are required in some years of the assessment period to meet reliability objectives.

MAIN – Generating capacity will be less than that required for adequate reliability in the late 1990s. Additional load management or short lead-time capacity will be needed to assure reliability. Should peak demand growth be above forecast, the timing of capacity additions will be critical.

NPCC – Peak demand and generating capacity projections indicate that additional resources beyond those already planned and committed will be required in New England as early as 1993. Unavailability of the Seabrook (1,150 MW) and Shoreham (809 MW) generating units in a Region where capacity shortages may occur in the early 1990s is of great concern. Dependency on uncommitted resources for generation adequacy puts the reliability of the electric supply in this Region at considerable risk. Frequent use of load management and selective use of voltage reductions to help limit peak demands occurred during the 1988 summer.

SERC – Use of load management will be required to maintain adequacy. If peak demand exceeds forecast, a generation deficiency could quickly develop. Further, the permitting and construction of a key 500 kV transmission line in Florida continues to be delayed requiring the operation of higher cost local generation to maintain system reliability.

MAAC-ECAR-SERC – Transmission limitations near the interfaces of these Regions restrict interregional electricity transfers. Reliability in these Regions is impaired because simultaneous needs for transmission capability cannot be met.

Because large generating units take eight years or more to build, utilities are relying on many different short lead-time options to forestall or prevent generating capacity deficiencies. These include: load management, conservation and other demand management programs, enhanced maintenance of older generating units, purchases from non-utility generators and other utilities, and short lead-time capacity additions such as combustion turbines. However, these options are not without risk.

Electric utility customers in the United States and Canada expect a reliable supply of electricity. That supply is being jeopardized in several geographic areas. Utilities and public policymakers must actively work together to thoroughly understand and manage these threats to the reliability of electricity supply in the United States and Canada.

RELIABILITY AND WHAT IT MEANS TO THE CUSTOMER

Electric utilities in the United States and Canada are dedicated to providing a reliable supply of electricity to their customers, and as a result, electric utility customers have come to expect a continuous and dependable supply of electricity. When that supply is disrupted, even for a short period of time, the results can produce a wide range of effects from minor inconvenience to economic loss to endangerment of human life.

One hundred percent reliability is not practical, nor can it be guaranteed or achieved at any cost. Unexpected equipment failures and other uncertainties, many out of the control of electric utilities, such as extreme weather conditions or fuel supply disruptions, can interrupt electrical supply. When conditions occur for which the electric systems were not designed, utilities may be required to resort to emergency operating procedures, including utility-controlled interruptions of customer service, to balance system demand and supply.

Bulk Electric System Reliability

In a bulk electric system, reliability is the degree to which the performance of the generation and transmission components of that system results in electricity being delivered to electric utility customers within accepted standards and in amounts desired.

The generation and transmission components of an electric system must be adequate to supply the electrical peak demand and energy requirements of its customers at all times while taking into account both the scheduled and unscheduled outages of these system components.

Reliability Criteria

Reliability must be planned and built into an electric system. The system must then also be operated in a reliable manner. Both planning and operations are well coordinated activities among the interconnected electric systems of the United States and Canada.

As the electric systems have grown, various planning policies and criteria have evolved to serve as guides to help maintain electric system reliability. All electric systems of NERC accept the responsibility to observe the NERC Policies, Criteria, and Guides and to contribute to their continued improvement. Further, each Regional Reliability Council has the primary responsibility for the development of reliability criteria applicable to its Region or area for use in planning and designing the expansion of its generation and transmission facilities. An April 1988 NERC report, *Overview of Planning Reliability Criteria of the Regional Reliability Councils of NERC*, presents a summary of the planning reliability criteria of the nine NERC Regions. Criteria concerned with the operation of interconnected electric systems are contained in the NERC *Operating Manual*.

All systems in NERC share the benefits of interconnected systems operation. However, they also recognize and accept the responsibility to plan, engineer, and operate their electric systems in a coordinated manner that will promote and maintain the reliability of their systems.

Consequences of Inadequate Reliability

Imagine if a major bulk electric system disturbance were suddenly to occur right now resulting in the outage of key generation or transmission system components and the interruption of the electrical supply for several hours or more. Think about your immediate surroundings and what this could mean to you or your family. Perhaps work, school functions, or home activities would be disrupted for an extended period of time. Would your safety or that of your family members be in jeopardy? Would your livelihood be affected and to what extent?

Most electric utility customers have experienced the effects of an electricity outage or interruption. In these circumstances, many of the modern conveniences and basic necessities taken for granted, such as heating, air conditioning, lighting, and refrigeration, become unavailable. Fortunately, the majority of electric system interruptions are confined to individual neighborhoods or localized areas, where perhaps due to a severe thunderstorm or a vehicle hitting an electric utility pole the local electricity supply is interrupted.

On occasion, deficiencies or multiple equipment outages or failures in either the generation or transmission segments of the electric system can occur. Such contingencies may result in major electric system disturbances interrupting the electrical supply to large numbers of customers over a widespread geographic area. This report is concerned with

assessing the future reliability of these generation and transmission segments, the so-called bulk electric portion, of electric utility systems.

Major Electric System Disturbances

Widespread electric supply disruptions can produce a myriad of impacts that can bring electrified, computer-dependent, highly-automated societies, such as in the United States and Canada, to an abrupt halt. On a more personal level, these electrical interruptions can also create problems in the heating, cooling, and lighting of homes and offices as well as problems with transportation and communications.

The effects of major electrical system disturbances highlight the importance of system reliability. Probably the most publicized and remembered electrical system disturbance in the United States was the one that occurred in the Northeastern part of North America in November 1965. This disturbance directly affected the lives of 30 million people and was the worst electric supply outage in U.S. history in terms of the number of people involved. Following the electrical system shutdown, it took up to 13 hours to restore service to most of the affected area, and economic losses were estimated at about $100 million.

More recently, on March 13, 1989, a solar magnetic disturbance caused five transmission lines emanating from the James Bay generation complex of Hydro-Québec to trip out of service resulting in a generating capacity loss of 9,450 megawatts (MW). The Hydro-Québec system was unable to withstand the sudden generation loss and collapsed within seconds, interrupting 19,400 MW of customer load in the province of Québec plus 1,325 MW of exports. All electric service was restored within nine hours.

Widespread electrical system disturbances have not been limited to North America. Examples of disturbances in large electric systems throughout the world also illustrate what can happen.

In July 1987, a large portion of Tokyo, Japan, was blacked out due to a major electrical system voltage disturbance that affected some 2.8 million electric customers.

In late 1988, Buenos Aires, Argentina, a city of 11 million people, began to experience severe electricity shortages because of extended outages at major generating plants and because a drought had reduced water supplies to hydroelectric plants. As a result, Buenos Aires and some provincial towns were taking turns with electrical supply interruptions — rolling blackouts.

Imagine working in Buenos Aires in a high-rise office building or living in a high-rise city apartment and having to schedule activities around elevator availability. Street lighting and working hours were reduced along with subway operation and television broadcasts. With limited refrigeration, the availability and storage of food was a concern. Shopping for food was forced to be a daily routine. Although a published schedule was supposed to indicate the hours of the day when electricity would be cut off, electrical interruptions outside the schedule were experienced and everyone was asked to conserve on electricity use.

Except for the Argentina situation, the causes of the above major electrical interruptions have been traced to misoperation of protective system components, malfunctions or failures of electrical system transmission equipment, equipment outages due to extreme weather conditions, or the lack of adequate voltage control equipment. Most of these disturbances have been infrequent occurrences which were rectified in relatively short periods measured only in hours of customer service interruption time.

In Argentina, generating capacity and energy shortages are the key reliability issues. These outages will affect many Argentinean citizens every day for several hours over an extended period. There are no "quick-fix" solutions or relief in sight. Argentina is faced with a long-term electrical capacity and energy deficiency.

To date, the systems within NERC have never experienced an Argentinean type of extended capacity and energy shortage. However, delays in the completion of planned generating units and transmission facilities, which are in various stages of planning, design, licensing, and construction, could adversely impact the reliability of electric supply. Deficiencies in system reliability due to delays in long lead-time facilities such as generating units and transmission lines could take several years to alleviate. A creeping degradation of the reliability of NERC's electric systems must be avoided. Fortunately, electric system blackouts have been rare occurrences in the areas within NERC. However, blackouts can occur when generation or transmission system reliability is compromised.

Socioeconomic Impacts

In the NERC areas of the United States and Canada, electricity has become an irreplaceable part of our way of living and conducting business. The more advanced our society becomes, the greater are the benefits of reliable electric service and the greater are the adverse societal and economic impacts of unreliable service.

If widespread electric supply interruptions occurred frequently in any Region, loss of revenues and lower industrial production could cause businesses to close or relocate to

areas where electric supply is considered more reliable. Loss of industrial activity would soon be accompanied by a decline in commercial and residential growth.

Reliable electric supply is not only valuable to individual customers or businesses, it is crucial to the economic health of a Region as well as that of the United States and Canada. Although the cost of major electric system disturbances can be extremely high, 100 percent electric system reliability is not practical and it cannot be guaranteed or achieved at any cost. Utilities and public policymakers must carefully balance the effects of outages and electric supply shortages against the cost of maintaining system reliability.

Protection Against Electric Supply Shortages

Electricity cannot be economically stored and must be produced on demand. That is, the supply of electricity must equal the demand at all times. The U.S. and Canadian electric utilities together operate complex and highly interconnected generation and transmission networks to supply their customers within the constraints of a balanced system. They are dedicated to meeting the electrical requirements of their customers through well coordinated planning and operations to assure that the supply of electricity is always equal to customer demand.

The electric utilities in the NERC Regions have built a strong record of reliability and are striving to maintain that record. From time to time, however, conditions can occur for which electric systems are not designed. Even when supply margins appear adequate, extraordinary events can place systems in a vulnerable position. Typical examples include an unusually large amount of unavailable generation, multiple outages of several circuits of the transmission systems, or unexpectedly high customer demand. When these conditions occur, and if time permits, utilities will rely on their emergency procedures to balance demand and supply and to protect against uncontrolled shutdown of the electric system and damage to equipment.

Emergency operating procedures are generally implemented after all available electric generating sources have been called upon and after all contractually interruptible customer demands have been interrupted. These procedures include public appeals to customers to voluntarily reduce their electrical demands, utility instituted system voltage reductions, and utility-controlled customer load shedding. Although these actions may result at times in customer inconvenience, the effects of these procedures are far less disruptive than the widespread uncontrolled system disturbances discussed above. For example, on several occasions during the summer of 1988, systems in MAAC, SERC, and NPCC instituted voltage reductions to balance demand and supply conditions so that they could continue to serve customer load. In some systems, public appeals were also instituted to reduce demands.

There is concern that some of these procedures, formerly relegated to system operators for alleviating system emergencies, are beginning to be used as long-range system planning options to reduce the need for new facilities. These actions will eventually degrade system reliability as there will be less system flexibility to handle emergencies. Electric utilities and public policymakers share the responsibility of ensuring that an adequate level of bulk electric system flexibility and reliability is available to meet future customer requirements.

System reliability should not be allowed to be compromised for short-term economic benefits that in the longer term could result in economic penalties to the customer and a degradation in electric service. The chapters that follow present, in substantial detail, the electric utilities' views of system reliability over the next ten years and the major challenges to that reliability.

PEAK DEMAND PROJECTIONS

The NERC 1989-1998 aggregated projections of peak demand for the United States and Canada are slightly higher than those made last year for 1988-1997. A comparison for 1997, the last common year of the two projections, shows that the summer peak demand for NERC-U.S. is 17,700 MW or about 3% higher than last year's projection, and the 1997/98 winter peak demand for NERC-Canada is 860 MW or about 1% higher. Similarly, the 1997 peak demand projections for eight of NERC's nine Regional Reliability Councils exceed last year's 1997 projections.

The uncertainty in the 1989-1998 estimates of peak demand for NERC-U.S. and NERC-Canada is illustrated by a bandwidth around each of their ten-year demand projections. For the United States, the bandwidth indicates that there is an 80% probability that the summer peak demand will increase at an annual rate between 1.2% and 2.5% over the 1989-1998 period. This corresponds to a NERC-U.S. summer peak in the range of 565,000 to 673,000 megawatts in 1998. For NERC-Canada, the annual growth is projected to be between 0.7% and 3.3% with the same probability, or a winter peak demand in the range of 74,100 to 108,000 megawatts in 1998/99.

Utilities in all Regions are using demand management programs to reduce system peak demands and thereby defer the need for new generating capacity. Load management, the direct utility-controlled portion of demand management, is expected to increase from the equivalent of 2.2% of the 1989 peak demand in NERC-U.S. (2.5% in NERC-Canada) to 2.8% (3.6% in NERC-Canada) of the 1998 peak demand.

1988 Peak Demands

The 1988 demand for electricity was higher than expected in NERC-U.S. and NERC-Canada due to a strong economy and extreme seasonal weather conditions. The NERC-U.S. and NERC-Canada projected 1988 peak demands were exceeded by 5.8% and 2.8%, respectively. The 1988 actual peak demands in all nine Regional Reliability Councils exceeded the 1988 projected peak demands as shown in Table 1. Only the winter peaking Canadian portion of MAPP did not achieve its projected 1988/89 peak demand.

In most Regions, the continued strength of the recent growth in peak demand, especially if actual demands continue to exceed forecast, is of concern from the viewpoint of the adequacy of future generation and transmission capacity. The reliability effects of peak de-

Table 1 — 1988 Actual Peak Demands

NERC-U.S. (Summer)	1987 Actual[a] (Thousands of MW)	1988 Actual[a] (Thousands of MW)	Actual Change (%)	1988 Forecast[b] (Thousands of MW)	1988 Actual vs Forecast (%)
ECAR	72.6	79.1	9.1	71.8	10.3
ERCOT	39.3	40.8	3.8	40.5	0.8
MAAC	40.5	43.1	6.4	39.6	8.9
MAIN	37.5	41.1	9.8	37.3	10.3
MAPP-U.S.	23.2	24.9	7.5	22.8	9.0
NPCC-U.S.	42.7	45.2	6.1	43.0	5.1
SERC	109.8	115.2	4.9	111.0	3.8
SPP	47.7	49.4	3.4	48.3	2.1
WSCC-U.S.	83.0	90.6	9.1	85.9	5.4
TOTAL (U.S.)	**496.2**	**529.5**	**6.7**	**500.3**	**5.8**
NERC-Canada (Winter)	**1987/88**	**1988/89**		**1988/89**	
MAPP-Canada	5.4	5.5	2.5	5.5	(0.6)
NPCC-Canada	52.1	53.4	2.3	51.7	3.1
WSCC-Canada	12.7	13.7	8.2	13.3	3.1
TOTAL (Canada)	**70.2**	**72.6**	**3.4**	**70.6**	**2.8**

Note: Figures are rounded. Percentages are based on complete data.
[a]Metered internal peak demands. (Unadjusted for operator-controlled demand reductions, emergency operating procedures, or weather.)
[b]Based on normal weather for each system within the respective Regions.

PEAK DEMANDS

Forecast peak demands represent total internal peak demands. Internal peak demands have already been reduced to reflect the effects of demand management programs, such as conservation, not under the direct control of utility system operators, and generally include those loads under the direct control or management of the utility system operators, such as utility-controlled water heaters and contractually interruptible customers.

The internal peak demand for a system is equal to the sum of the metered (net) power outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system. Thus, internal peak demand is the maximum hourly integrated demand of all customer demands plus losses.

mand exceeding forecast are discussed further in the "Demand Exceeding Forecast" chapter.

1989-1998 Forecast

The electrical peak demand in NERC-U.S. is projected to grow at 2% per year, and the United States is expected to continue to be summer peaking over the 1989-1998 forecast period. NERC-Canada is projected to be winter peaking throughout the forecast period with its winter peak growing at 2.2% per year. These peak demand forecasts and the annual net energy for load projections are summarized in Table 2. The growth rates for annual energy are slightly higher than the growth rates for peak demand in both the United States and Canada. This trend will result in higher system annual load factors and increased utilization of existing and future generation and transmission facilities.

Table 2 — 1989-1998 Forecast of Peak Demand and Energy

NERC-U.S.	1989	1998	1989-1998 (%/yr)
Summer Peak Demand[a] (Thousands of MW)	522	623	2.0
Annual Net Energy for Load (Millions of MWh)	2802	3349	2.0
NERC-Canada			
Winter Peak Demand[a,b] (Thousands of MW)	75	91	2.2
Annual Net Energy for Load (Millions of MWh)	418	517	2.4

Note: Figures are rounded. Percentages are based on complete data.
[a]Forecast uncertainty is illustrated in Figures 1 (U.S.) and 2 (Canada).
[b]1989/90 and 1998/99 winter peak demands, respectively.

Figures 1 and 2 illustrate the 1989-1998 projections of peak demand for the NERC-U.S. and NERC-Canada in relation to recent historical peak demands. These actual demands have not been adjusted for the effects of emergency operating procedures or for weather conditions that occurred at the time of peak. The current projections are influenced by the sustained growth in the U.S. and Canadian economies since the mid-1980s.

Peak demand and annual energy growth rates for each of the nine Regional Reliability Councils are presented in the introduction to the Regional Assessments section of this report. The 1989 forecasts of peak demand have increased in eight of the nine Regions compared to 1988's ten-year projection. For example, the projected 1997 peak demands

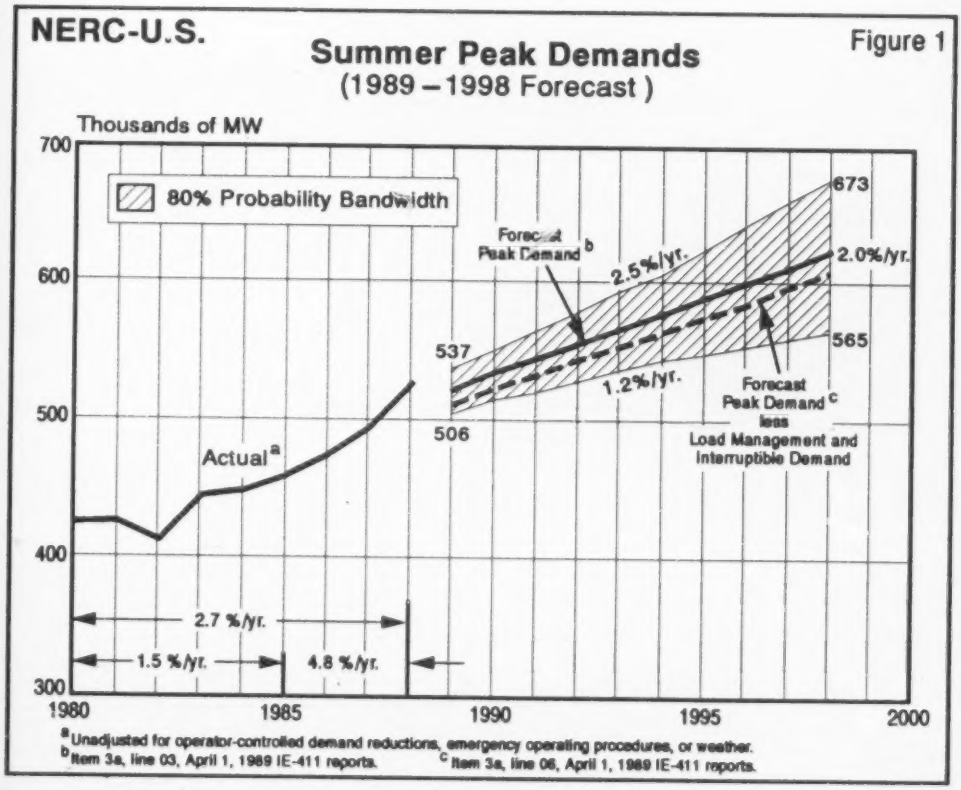
ACTUAL VERSUS FORECAST PEAK DEMANDS

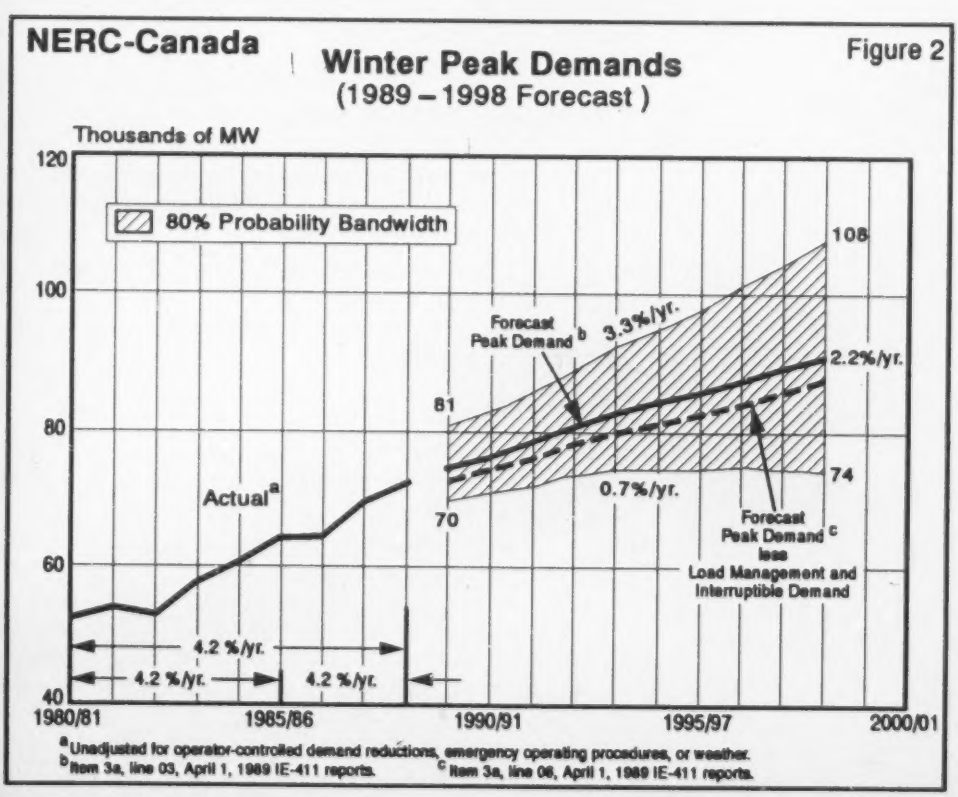
In this report, regional actual peak demands have not been adjusted for variations from normal weather conditions, demand reductions due to load management actions, or emergency operating procedures that were in effect during the peak hour.

Regional forecast peak demands are based on the expectation of normal weather conditions, and are not generally reduced to account for direct control load management programs or emergency operating procedures that could be used if required.

Conclusions made from a comparison between actual and forecast peak demands must be made with caution. Adjustments to one or both quantities may be necessary to assure consistent treatment of direct control load management and emergency operating procedures. Proper adjustments are also required so that the actual and forecast peak demands reflect the same weather conditions.

The process of adjusting actual peak demand to the peak demand that would have been expected if weather conditions were "normal" is called weather-correcting or weather normalization. This is a complex calculation that can result in a lower weather-corrected actual peak demand if weather conditions during the peak were warmer than normal or in a higher weather-corrected actual peak demand if conditions were cooler than normal for summer peaking systems. Just the opposite effects occur for winter peaking systems.





in eight of the Regions range from 1% to 6.6% over the 1997 peak demands projected last year. Only ERCOT's 1997 peak demand projection decreased.

Forecast Uncertainty

The NERC projections of peak demand and annual energy are aggregates of the forecasts, as of January 1989, of the individual utilities comprising the Regional Reliability Councils. The individual utility forecasts are generally equal probability forecasts. That is, there is a 50% chance that the forecast will be exceeded and a 50% chance that the forecast will not be reached.

Because electric demand and annual electrical energy requirements are reflections of the ways in which customers use electricity in their domestic, commercial, and industrial activities, the utilities' forecasts are subject to change. Utilities continually monitor their peak demand and energy requirements and typically update these projections annually.

To avoid implying a degree of certainty not intended in the ten-year forecasts, bands of reasonable variation about the aggregated forecasts have been developed. The sensitivity bandwidths for the 1989-1998 aggregated peak demand forecasts for NERC-U.S. and NERC-Canada are shown in Figures 1 and 2, respectively.

In developing the U.S. bandwidth, the variables found to relate best to growth in electrical energy were the gross

NET ENERGY FOR LOAD

The annual net energy for load (NEL) represents the annual electrical energy needed to serve an electric utility's customers. NEL is not just the energy sold to customers, but includes transmission losses and represents the electrical energy generated by the utility's generating sources plus electrical energy purchases from other electric utilities and non-utility generators, less electrical energy sales to other electric utilities. NEL does not include energy pumping (or charging) requirements for pumped storage (or other energy storage) generating facilities.

national product, the price of electricity, and the price of natural gas. Relationships between these variables and annual net energy for load were determined. High and low estimates of the variables were then selected to develop high and low annual energy projections about the base or equal probability annual energy projection.

The high and low bounds of the summer peak demand bandwidth of Figure 1 were estimated by a statistical sampling of the historical relationship between peak demand and annual energy. The resulting bandwidth range of peak demand growth rates for NERC-U.S. is 1.2% to 2.5% per year. This bandwidth has been defined such that there is an 80% probability that the future NERC-U.S. summer peak demands will fall within the high and low bounds of the bandwidth. This means there is a 10% chance that future U.S. summer peak demands in any year will exceed the upper bound of the bandwidth on Figure 1. Similarly, there is a 10% chance that future demands will be less than the lower bound of the bandwidth.

The variables used in developing the NERC-Canada winter peak demand bandwidth of Figure 2 are the domestic national product, the price of electricity, heating degree days, a weighted average of the price of natural gas and oil, and the effect of utility marketing efforts in the industrial sector. The resulting range of average annual winter peak demand growth rates in Canada is 0.7% to 3.3%. The Canadian and U.S. forecast bandwidth calculation methodologies are similar except for the variables.

It would be incorrect and misleading to apply the absolute value or percentage range of the forecast bandwidths shown in Figures 1 or 2 to the forecasts of individual Regional Reliability Councils, individual utilities, or groups of utilities since the bands shown represent a composite of all member utilities in each country.

Demand Management and Load Management

Demand management programs, which include conservation and load management and other programs as described in the sidebar, provide utilities with the ability to reduce peak demand and to possibly delay the need for some future electric generating capacity. However, demand management is not an unlimited resource and may only provide limited demand reduction assistance. It may also reduce the rate of growth in peak demand and thereby delay when a given peak demand may occur, but it will not eliminate growth.

Some utilities have been heavily involved in demand reduction or peak shifting programs for many years, while others are just initiating programs now to gain experience and to provide flexibility and reduce capacity requirements in the future. However, SERC, NPCC, and MAAC will be heavily dependent on the success of these programs in satisfying their generating capacity margin requirements over the next ten years. These programs are being employed to various degrees throughout the NERC Regions.

Load management is that portion of demand management under the direct control of electric utility system operators or interruptible by the customer at the utility's request. The amount of load management is generally included in (not

DEMAND MANAGEMENT

In this report, "demand management" is the umbrella term used to include all activities undertaken by an electric utility or its customers to influence the amount and timing of electricity use. It includes conservation programs, improvements in the efficiency of both primary energy and electricity use, utility control of certain customer loads, economic incentives embodied in rate design, contractually interruptible customers, and many other similar activities.

LOAD MANAGEMENT

In this report, the term "load management" includes only that portion of demand management concerned with customer loads under the direct control of the electric utility system operator or interruptible by the customer at the utility's request in accordance with contractual arrangements. The direct switching of water heaters, air conditioners, and irrigation pumps are typical examples of customer loads that are controlled by utilities. Reductions in customer load using load management are generally achieved within minutes but may take up to a few hours.

subtracted from) the peak demand projections for NERC-U.S. and NERC-Canada.

Load Management Projections

During the 1988 summer and 1988/89 winter peak demand periods, utilities in several Regions exercised their directly controlled load management options to help reduce their peak demands. The use of load management will vary among Regions due to contract arrangements and due to the need to reduce peak demand for overall system reliability.

The actual peak demands reported for each Region include a range of possible load management effects. Some systems may not have exercised their load management options at the time of system peak while others may have reduced their peak demand using load management to the maximum extent possible.

The 1989-1998 projections indicate that about 2.8% of the summer peak demand in NERC-U.S. and 3.6% of the winter peak in NERC-Canada will be under utility-controlled load management by 1998. The associated peak demand reductions projected to be available from load management are illustrated on Figures 1 and 2 for the United States and Canada, respectively. It is this reduced demand against which capacity resources have been compared in the "Generation Reliability Assessment" chapter.

There is substantial uncertainty as to how much peak demand reduction will be realized at the particular time when load management is needed and implemented. Another major concern is that customers, who initially participate in load management programs because of the financial incentives, may decide, once the electric supply to their equipment has actually been interrupted a number of times, that the inconvenience of the interruptions outweighs the cost savings and withdraw from the programs.

A comparison of the 1989-1998 forecast with last year's ten-year projection indicates that the NERC-U.S. load management programs in 1997 will approach 16,800 MW or a 29% increase over last year's 1997 projection. The current 1997 load management projection for NERC-Canada is 4.8% higher than last year. The ability to control peak demands through load management among the nine Regions currently ranges from the equivalent of 0.9% to 3.2% of peak demand. By 1998, the range will vary among the Regions from 1.1% to 5.3% of projected peak demands. More experience will be required to establish the long-term availability, effectiveness, and customer acceptance of these programs.

GENERATION RELIABILITY ASSESSMENT

Planned capacity resources are judged to be adequate to meet the base ten-year peak demands in Canada, but are projected to be insufficient in the United States by 1998 unless additional capacity commitments are made.

Possible delays of new capacity and loss of existing capacity could cause shortfalls in the combined Eastern and Québec Interconnection by 1997 and in Canada by the winter of 1996/97, and accelerate the deficiency in the United States by two years. Demand growth approaching the upper bound of the forecast bandwidth could cause capacity deficiencies in all Interconnections before the end of the assessment period and as early as 1993 in the combined Eastern and Québec Interconnection.

Not all utilities and Regions will experience these potential problems to the same degree or at the same time. Specific generation reliability concerns are highlighted in the Regional Assessments section of the report.

Non-utility generators (NUGs) are projected to account for 19,100 MW or 20.4% of the planned capacity additions in NERC over the next ten years. NUGs will comprise about 3.6% of NERC's total planned capacity resources by 1998 and are anticipated to supply about 5.2% of the annual energy requirements. The extent to which the Regions are relying on NUGs varies from less than 1% to over 7% of their 1998 total capacity resources.

Compared to last year, the generating capacity projected for 1997 is 2,400 MW higher in the United States. Most of this change consists of oil and gas units. In Canada, the increase of 1,400 MW is largely NUGs and hydro capacity.

Generation Reliability Factors

An evaluation of planned capacity resources requires an assessment of both the existing capacity resources and the planned capacity additions. In the case of additions, the assessment includes an evaluation of generator unit construction status, non-utility generation reliability concerns, a comparison of recent capacity projections, and uncertainties associated with meeting scheduled service dates. An assessment of overall generation reliability would include an evaluation of those factors shown in Figure 3. Several of these key factors are briefly discussed in the following sections and quantified in this assessment.

Figure 3

Influences on Capacity Requirements

1989-1998 Capacity Projections

Capacity additions of 93,600 MW are planned over the 1989-1998 assessment period. A summary of generating unit additions and retirements is shown in Table 3. Utility-owned coal and nuclear generating units account for 34.2% of the U.S. generating capacity additions over the next ten years, and oil and gas units 28%. Non-utility generators (NUGs) comprise a significant portion of the U.S. additions at 25.1%. In Canada, nuclear, hydro, and coal-fired generating units comprise 90.9% of the planned capacity additions.

Generating Unit Construction Status

The relatively few remaining nuclear units planned for service over the next ten years are well along in construction with all but one being more than 50% complete. Two units (809 MW Shoreham and 1,150 MW Seabrook) are 100% complete but have not been permitted to become operational.

Of the planned coal-fired units, 67% of those in the United States and 30% in Canada are in some phase of construction. This and similar data are shown for utility and non-utility planned capacity additions in Table 4. A substantial portion of hydro and other (utility) additions are not yet under construction, and about 90% of the non-utility generation additions are not reported to be under construction.

About 27,500 MW, or 29.7% of the total planned additions in the United States and Canada, consist of utility-owned units 100 MW or larger that are not yet under construction. Figures 4 and 5 indicate that about 2,100 MW of these units have projected in-service dates of 1993 or earlier. In addition, about 10,500 MW of NUG units of various sizes, scheduled for service by 1993, are not reported to be under construction. Recognizing necessary lead times, it is likely that much of this 12,600 MW of new capacity not yet under construction will not be completed on schedule.

NON-UTILITY GENERATORS

An April 1987 reference document, *Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems*, is available from the North American Electric Reliability Council. This document defines non-utility generators as facilities for generating electricity that are not owned exclusively by an electric utility and which operate connected to an electric utility system. Included are qualifying cogeneration and small power production facilities under the Public Utility Regulatory Policies Act (PURPA) of 1978, pre-PURPA non-utility owned generators, customer-owned generators not covered by PURPA, and industrial or other independent power producers that operate connected to an electric utility system.

In this 1989 Reliability Assessment report, the data on non-utility generators (NUGs) is limited to only those non-utility generators which sell or are projected to sell electric energy or capacity, or both, to electric utilities. Data on industrial or other independently-owned generators that generate electricity for their own consumption are generally excluded from this report.

Utility units covered by sale-leaseback arrangements are not considered as NUGs based on the premise that most will be utility operated and will revert to the utility upon termination of the lease.

Table 3 — Generating Unit Additions and Retirements (1989-1998 Forecast)

Type	NERC-U.S. Thousands of MW	NERC-U.S. % of Total	NERC-Canada Thousands of MW	NERC-Canada % of Total	NERC-Total Thousands of MW	NERC-Total % of Total
Nuclear	11.2[a,b]	15.5	3.5	17.1	14.7[a,b]	15.7
Coal	13.5	18.7	4.2	20.5	17.7	18.9
Hydro	1.4	1.9	11.0	53.3	12.4	13.3
Oil/Gas	20.2	28.0	1.0	4.5	21.8[c]	23.3
Pumped Storage	2.4	3.3	0.0	0.0	2.4	2.5
Other (Utility)	5.4	7.5	0.0	0.0	5.5[c]	5.9
Non-Utility Generators	18.1	25.1	1.0	4.6	19.1	20.4
Additions	**72.2**	**100.0**	**20.7**	**100.0**	**93.6**	**100.0**
Retirements	**6.6**		**0.2**		**6.8**	

Note: Figures are rounded. Percentages are based on complete data.
[a]Includes the Shoreham 809 MW nuclear unit.
[b]Perry 2 and Washington Nuclear Project units, WNP 1 and 3, are not included.
[c]Includes 600 MW of oil-fired and 104 MW of geothermal additions in that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Non-Utility Generation

All nine Regional Reliability Councils have some level of NUG activity. By the summer of 1998, NUGs are projected to total 29,831 MW or about

Table 4 — Construction Status of Generating Unit Additions (1989-1998)

	NERC-U.S.			NERC-Canada		
	Number of Units	Thousands of MW	% of Total MW	Number of Units	Thousands of MW	% of Total MW
Nuclear[a]						
Not Yet Under Construction[b]	0	0.0	0.0	0	0	0.0
Under Construction (<50%)	0	0.0	0.0	1	0.9	25.0
Under Construction (>50%)	10	11.2	100.0	3	2.6	75.0
Total Nuclear	**10**	**11.2**	**100.0**	**4**	**3.5**	**100.0**
Coal						
Not Yet Under Construction[b]	18	4.4	32.9	11	2.9	69.6
Under Construction (<50%)	6	4.7	34.9	2	0.5	12.6
Under Construction (>50%)	6	4.4	32.2	2	0.8	17.8
Total Coal	**30**	**13.5**	**100.0**	**15**	**4.2**	**100.0**
Hydro[c]						
Not Yet Under Construction[b]	62	0.9	63.1	42	6.9	62.3
Under Construction (<50%)	9	0.3	18.6	10	1.2	10.9
Under Construction (>50%)	8	0.2	18.3	10	2.9	26.8
Total Hydro	**79**	**1.4**	**100.0**	**62**	**11.0**	**100.0**
Other (Utility)						
Not Yet Under Construction[b]	244	24.1	86.0	11	0.9	97.3
Under Construction (<50%)	23	3.2	11.6	0	0	0.0
Under Construction (>50%)	9	0.7	2.4	1	<0.1	2.7
Total Other (Utility)	**276**	**28.0**	**100.0**	**12**	**1.0**	**100.0**
Non-Utility Generators (NUGs)						
Not Yet Under Construction	-	16.1	88.9	-	0.9	93.1
Under Construction (<50%)	-	0.9	5.2	-	<0.1	4.6
Under Construction (>50%)	-	1.1	5.9	-	<0.1	2.3
Total NUG	-[d]	**18.1**	**100.0**	-[d]	**1.0**	**100.0**
Total (All Units)						
Not Yet Under Construction	-	45.5	63.0	-	11.6	56.2
Under Construction (<50%)	-	9.1	12.7	-	2.7	12.9
Under Construction (>50%)	-	17.6	24.3	-	6.4	30.9
Total (All Units)	-[d]	**72.2**	**100.0**	-[d]	**20.7**	**100.0**

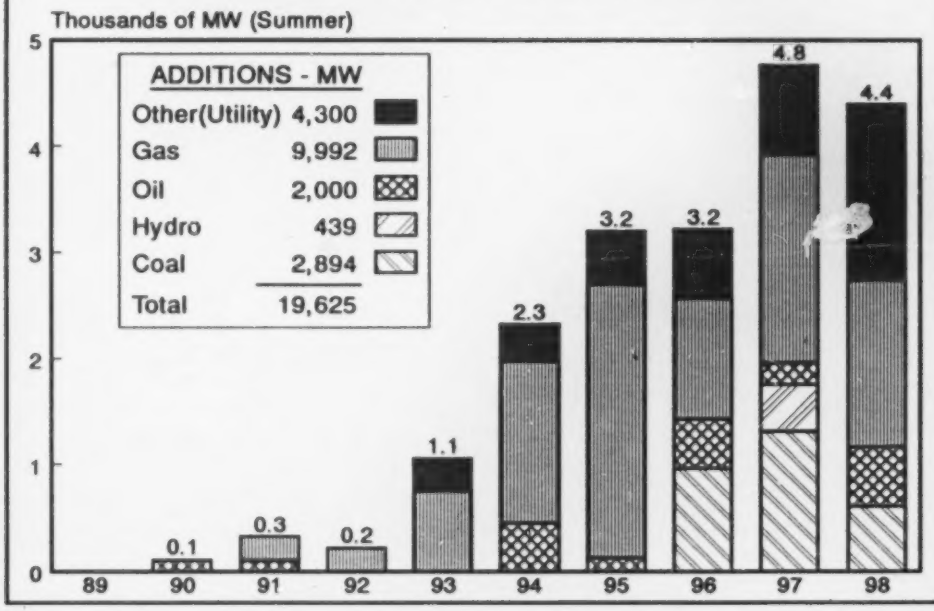
Note: Figures are rounded. Percentages are based on complete data.
[a]Perry 2 and Washington Nuclear Project units, WNP 1 and 3, are in some stage of construction but are not included.
[b]Includes utility units planned but not utility authorized, units with regulatory approval pending, and units with regulatory approval received but not yet under construction.
[c]Does not include pumped storage.
[d]Non-utility generator additions are not available by unit.

3.6% of the 1998 total planned capacity resources of NERC. A breakdown of 1998 NUG capacity is shown in Table 5.

Rapid growth in non-utility generation has occurred over the last few years. This growth has, in many respects, benefited both electric utilities and their customers. However, this projected use of NUG capacity has also prompted increased attention to reliability-related concerns. These concerns are discussed in the "Non-Utility Generation" portion of the "Reliability Issues" chapter.

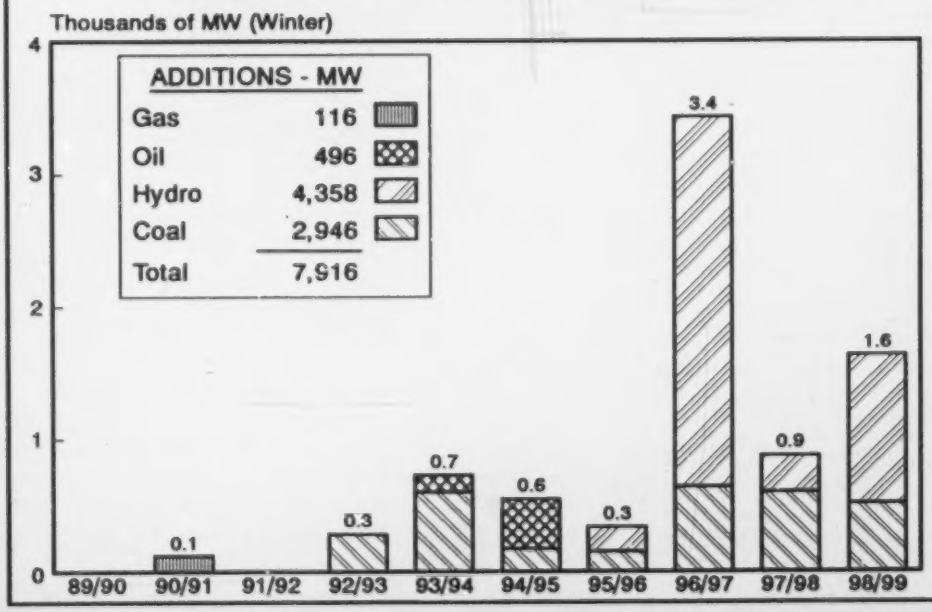
NERC-U.S. Figure 4

Utility-Owned Generator Unit Additions
100 MW or More – Not Yet Under Construction



NERC-Canada Figure 5

Utility-Owned Generator Unit Additions
100 MW or More – Not Yet Under Construction



Comparison of Recent Capacity Projections

A comparison of last year's and this year's forecast of generating capacity for the summer of 1997 in the United States and the winter of 1997/98 in Canada, respectively, is shown in Tables 6 and 7.

The U.S. total projected generating capacity in 1997 is about 2,400 MW higher than last year's forecast for that year. This consists primarily of a 5,100 MW increase in oil- and gas-fired units partially offset by decreases in other types. Similarly, the total projected winter capacity for Canada in 1997/98 has increased by 1,400 MW over the previous forecast. For both countries, the change in capacity is modest, representing an increase of only 0.33% in the United States. The 1.4% increase in Canada is largely NUGs and hydro capacity.

Planned Capacity Resources Uncertainty

All future plans are subject to uncertainty, and plans for generation capacity are no exception. New utility units are subject to delays due to licensing, regulation, and public intervention, as well as to the complexities of construction of large projects. Non-utility generation plans are also subject to variance from forecast due to changes in the economic climate and, in some cases, regulatory and tax treatment. In addition, changing requirements for associated cogenerator processes, such as steam requirements, could affect the future operation of some NUG capacity.

Table 5 — Existing and Planned Non-Utility Generators (NUGs) by Summer 1998

Region	Total Projections MW	% of Total Capacity Resources
ECAR	2,497	2.4
ERCOT	1,324	2.2
MAAC	4,135	7.1
MAIN	79	0.2
MAPP	458	1.1
NPCC	5,981	4.4
SERC	5,107	3.1
SPP	511	0.7
WSCC	9,739	6.3
NERC-Total	**29,831**	**3.6**
NERC-U.S.	**28,839**	**3.9**
NERC-Canada	**992**	**1.0**

The continued operation of existing utility generating capacity is also subject to uncertainty. Taking into account planned retirements, reratings, and the return of some presently idle capacity to service, the usable amount of today's capacity will likely decrease as that capacity ages. About 15% of the installed U.S. coal-fired capacity (6% in Canada) will be over 40 years old by the end of the assessment period. The extent to which older capacity will continue to be available for service is dependent upon the economic viability of continued operation, the success of generating unit availability improvement efforts currently under way at many utilities, and the resultant effects that environmental legislation and regulations may have on that capacity. This includes the U.S Environmental Protection Agency's application of New Source Performance Standards to maintenance projects as in the case of Wisconsin Electric Power Company in MAIN. Additional information on this example can be found in the "Environmental Considerations" portion of the "Reliability Issues" chapter.

To quantify the uncertainties that exist concerning new capacity additions, a NERC survey was conducted in 1988 regarding the likelihood of delays to the scheduled in-service dates of new generator additions. Recent experience has tended to verify the survey projections. Based on the results of this survey, the effects of delays of planned capacity additions, both utility and non-utility, could reduce 1998 planned capacity resources by about 7,400 MW in the United States and by 3,000 MW in Canada.

The possible loss of existing capacity, primarily as a result of likely changes in the Clean Air Act in the United States, was estimated in early 1989. By 1998, an estimated 12,600 MW of coal-fired capacity could be permanently removed from service in the United States as a consequence of such legislation through deratings, increased power requirements for scrubbers, anticipated poorer availability of some units retrofitted with emissions controls, and premature retirements.

There is also a possible loss of existing capacity in Canada. This lost capacity, which amounts to about 1,500 MW by 1998, is primarily a result of aging, in terms of technological obsolescence or loss of economic viability of continued operation. In contrast to the situation expected in the United States, less than 500 MW of existing coal-fired capacity is expected to be lost in Canada due to further acid gas regulations. This small reduction is primarily due to the much lower percentage of coal-fired capacity in Canada and the much younger age of the units as well as the wide use of low sulfur coals.

By the end of the forecast period, delays of new capacity and possible reductions in existing capacity could reduce resources by 23,400 MW and result in 1998 capacity resources in the United States of about 715,000 MW. Similarly, such effects in Canada could reduce resources by 5,000 MW and result in 1998/99 capacity resources of about 100,000 MW.

Capacity Resources Adequacy

Not all installed capacity is available at any given time due to full or partial forced outages, seasonal deratings, and maintenance requirements. The amount of such reduction in capacity availability at the time of peak demand is reported each year by each Region and subregion. Therefore, planned capacity resources have been reduced to reflect this typical unavailability of generation during peak demand periods and the results are shown in Figures 6 and 7 as the line labeled "Projected Available Resources." The projected available resources line provides an indication of the capacity that can be expected to be available to supply the peak demand if the planned capacity resources are placed in service on schedule. In each case, the planned capacity resources have been reduced by the weighted average unavailable capacity of each of the Regions within the area depicted by the figures, as well as by an appropriate amount of spinning reserve capacity required for normal system regulation.

Recent actual and projected peak demands are also shown in Figures 6 and 7 for the United States and Canada, respectively. The ranges of uncertainty associated with the forecast peak demands take into account the effects of projected load management and interruptible demands (from Figures 1 and 2). The result is a comparison of the projected available capacity resources with the forecast peak demands (less load management and interruptible demand)

for the United States and Canada, respectively. These figures indicate that the planned available resources are adequate to supply the forecast load-managed peak demands in Canada throughout the next decade but a capacity resource shortfall will occur in the United States by 1998. The effects of capacity delays and environmental requirements could cause a shortfall in the United States by 1996 and in Canada by the winter of 1996/97.

Table 6 — Projected Generating Capacity — 1997 Summer Comparison of Forecasts for NERC-U.S.

Projected Generating Capacity	This Year's Forecast For 1997 (Thousands of MW)	% of Total	Last Year's Forecast For 1997 (Thousands of MW)	% of Total	Change in Forecast For 1997 (Thousands of MW)
Coal	302.4	41.6	301.4	41.6	1.0
Nuclear	104.9	14.4	107.2	14.8	-2.3
Hydro	67.0	9.2	68.8	9.5	-1.8
Oil/Gas	200.8	27.6	195.7	27.0	5.1
Pumped Storage	18.6	2.6	18.4	2.5	0.2
Other (Utility)	4.6	0.6	5.6	0.8	-1.0
NUGs	28.9	4.0	27.7	3.8	1.2
Total	**727.2**	**100.0**	**724.8**	**100.0**	**2.4**

Note: Figures are rounded. Percentages are based on complete data.

The forecast peak demand is the base demand with a 50% chance of actual demand being either higher or lower than forecast. Similarly, the upper bound of the forecast peak demand represents demand values that there is only a 10% chance of exceeding. Since the range of uncertainties of available resources and peak demand overlap, the adequacy of capacity resources as presently planned is at risk depending upon these uncertainties. In order to demonstrate the possible consequences of such uncertainties, Figures 8 and 9 were developed.

Figures 8 and 9 compare the peak demand for both 50% and 10% probabilities of occurrence with the projected available resources with and without the effects of new capacity delays and the loss of existing capacity. These figures indicate a 10% likelihood of shortfall of capacity by 1993 in the United States and immediately in Canada, even if projected available resources are realized. It should be noted that the benefits of load management and interruptible demands to reduce capacity requirements have already been taken into account. It should also be recognized that weather effects are reflected in the forecast peak demands on a statistical basis averaged over time and that weather extremes could cause demand to exceed available capacity earlier than would otherwise be projected.

The planning of generation is not a static but a dynamic activity. Supply plans are modified with changing demand forecasts. Therefore, the occurrence of actual demands near the higher bound of the demand forecast without a change in planned capacity resources is not likely. However, recognition of a significant change in growth rate must occur soon enough to permit ameliorative actions, whether they consist of demand management activities or the addition of generating capacity. Accordingly, the lead-time requirements for both short lead-time and baseload capacity additions have also been shown on Figure 8. Short lead-time capacity is a practical supply option for the 50% probable demands and could be an option for 10% probable demand in the United States only. However, while baseload capacity may be a practical supply option for 50% probable demand in Canada, baseload capacity alone is not a practical option for either probable demand in the United States.

Table 7 — Projected Generating Capacity — 1997/98 Winter Comparison of Forecasts for NERC-Canada

Projected Generating Capacity	This Year's Forecast For 1997/98 (Thousands of MW)	% of Total	Last Year's Forecast For 1997/98 (Thousands of MW)	% of Total	Change in Forecast For 1997/98 (Thousands of MW)
Coal	21.7	21.5	21.9	22.0	-0.2
Nuclear	15.5	15.3	15.5	15.6	0.0
Hydro	53.3	52.7	52.8	52.9	0.5
Oil/Gas	9.3	9.2	9.2	9.2	0.1
Pumped Storage	0.0	0.0	0.0	0.0	0.0
Other (Utility)	0.3	0.3	0.0	0.0	0.3
NUGs	1.0	1.0	0.3	0.3	0.7
Total	**101.1**	**100.0**	**99.7**	**100.0**	**1.4**

Note: Figures are rounded. Percentages are based on complete data.

Interconnection Analysis

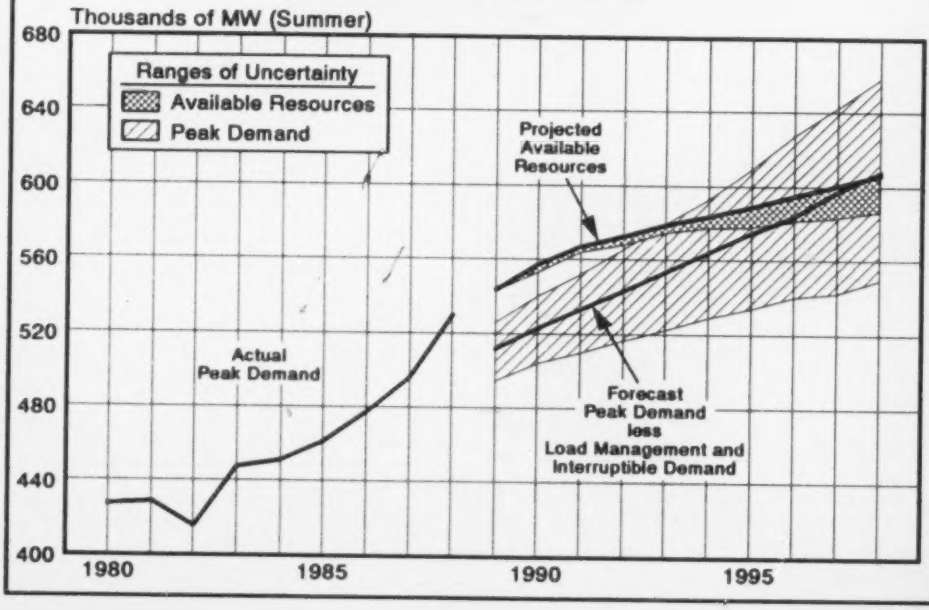
The preceding analysis was based on aggregate information on a national basis. However, there are limits to the degree that available capacity in any area of either nation can supply peak demand requirements for another area. This is particularly the case if more than one Interconnection is involved. Transfer capabilities between the Eastern, Western, and Texas Interconnections are very limited. This is true to a lesser extent between the Eastern Interconnection and Québec. Within Interconnections, there is a greater capability of transferring electricity among the interconnected systems although limitations still do exist. Accordingly, an analysis similar to the national ones has been made for each of the Interconnections. Figures 10, 11, and 12 show ranges of uncertainty for peak demand and projected available resources for the Western, Texas, and the combined Eastern and Québec Interconnections, respectively.

Each of the Interconnections was analyzed for both the summer and winter seasons, but the summer season was the most critical. Not surprisingly, each of the Interconnections was unique as each has its own characteristics.

The greatest likelihood of an early capacity shortfall is in the combined Eastern and Québec Interconnection in the summer season. The comparison of probable peak demands and projected available resources is shown in Figure 13. The 10% likelihood of capacity shortfall could occur by 1993 assuming

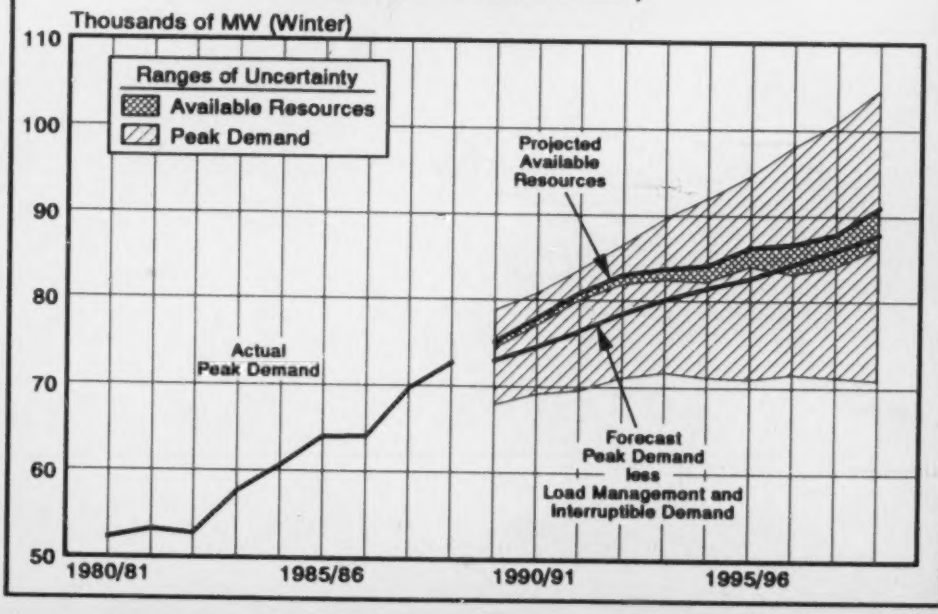
NERC-U.S. Figure 6

Ranges of Uncertainty for Peak Demand and Projected Available Resources
(1989 – 1998 Forecast)



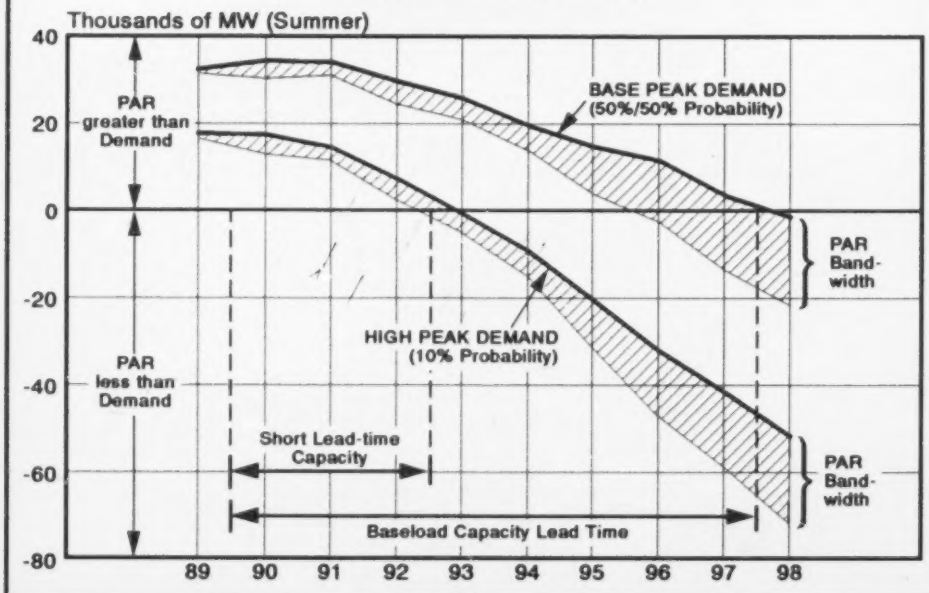
NERC-Canada Figure 7

Ranges of Uncertainty for Peak Demand and Projected Available Resources
(1989 – 1998 Forecast)



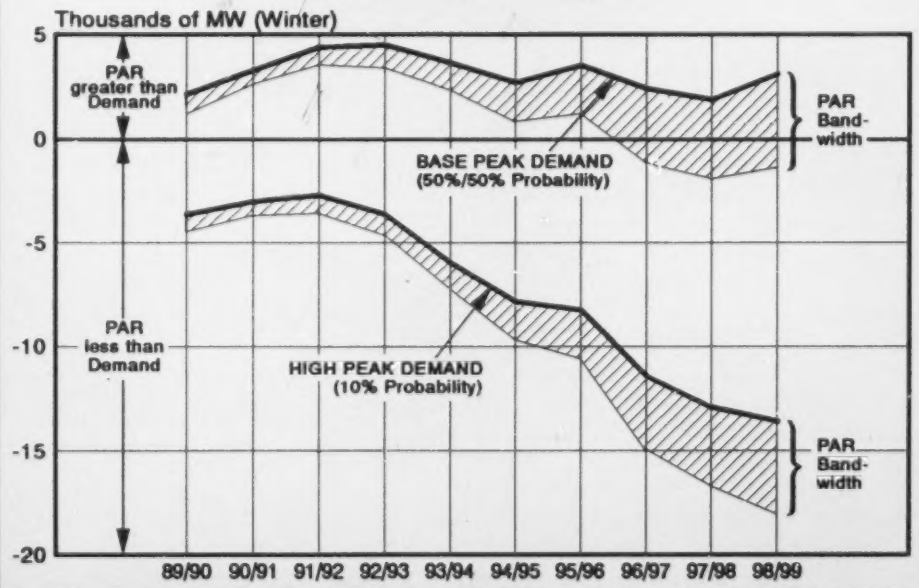
NERC-U.S. Figure 8

Projected Available Resources (PAR)
Less Probable Peak Demands
(1989 – 1998 Forecast)



NERC-Canada Figure 9

Projected Available Resources (PAR)
Less Probable Peak Demands
(1989 – 1998 Forecast)



projected available resources are attained. Even if the forecast peak demand is not exceeded over the next ten years, the capacity available to supply the load-managed demand at the end of the decade is at risk. The effects of environmental restrictions and new capacity delays could also cause a capacity shortfall by 1997 unless replacement capacity is constructed in a timely manner. This shortfall could occur a year earlier, depending upon the Québec to Eastern transfer capability at that time.

The projections included in Figures 6, 7, 8, and 9 apply to the aggregate peak demand and capacity resources of the United States and Canada and, therefore, cannot be inferred to reflect the situation in any Regional Council, utility, or group of systems in either country. Similarly, the projections included in Figures 10 through 13 apply only to those Interconnections.

Capacity Resource Concerns

The potential for loss of existing capacity, primarily due to possible environmental regulations, is difficult to address. The amount of loss, and more importantly the timing, is highly uncertain. In any event, the loss will have to be replaced to achieve the planned capacity resources necessary to meet the forecast peak demand requirements.

If sustained peak demand growth is greater than projected, capacity plans will have to be modified. It could take several years to confirm an

increase in growth rate. It may then be too late to install baseload generation as typical baseload capacity lead times are in the range of eight years or more. Utilities may be limited to short lead-time generation options. Even these require three years minimum lead time. Siting considerations may also preclude a timely response except for the installation of combustion turbines at existing sites.

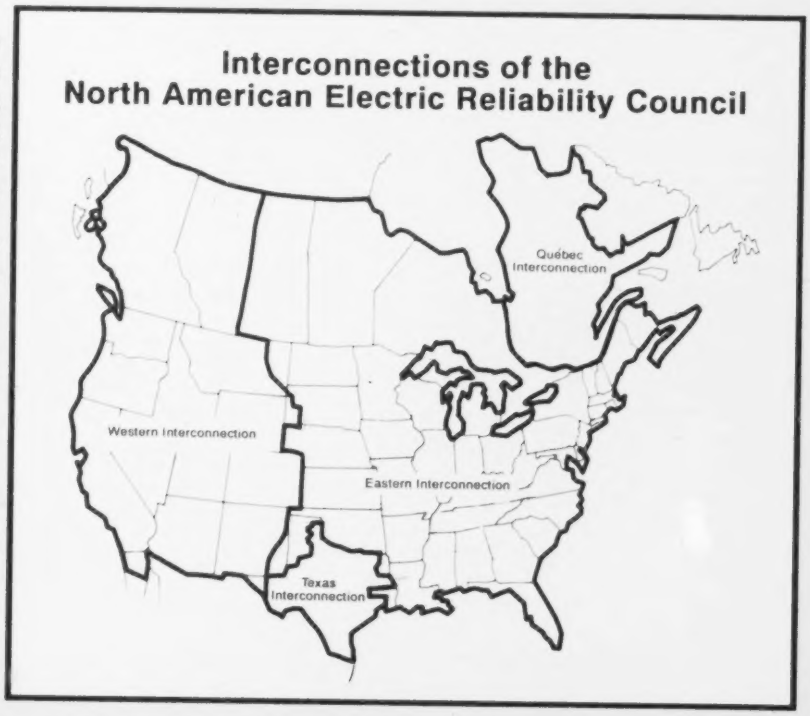
Relying on short lead-time options could cause many orders for generation equipment to be placed in the same short period. This equipment might require delivery at essentially the same time, which could exceed the capabilities of the equipment manufacturers to produce the equipment when needed. This in turn, could result in some utilities seeking to rely on the resources of their utility neighbors. However, these neighbors could also be facing the same capacity dilemma and not be in a position to provide sufficient assistance.

Load Management

Load management is being used by many utilities to reduce peak demand and delay generating capacity additions. The effects of peak demand reductions projected to be available from load management programs (including interruptible demands) have been taken into account in Figures 6, 7, 8, and 9 for the United States and Canada, and in Figure 10 through 13 for the Interconnections.

INTERCONNECTIONS

In the one hundred-year history of the electric utility industry, utilities have grown from isolated systems supplying their customers from local generating sources to highly interconnected systems (or "Interconnections") of generating stations and high voltage transmission lines encompassing large geographic areas and many individual utilities. Today, in NERC, there are four major interconnected areas: the Eastern Interconnection, the Western Interconnection, the Texas Interconnection, and the Québec Interconnection, as defined in the adjacent map.



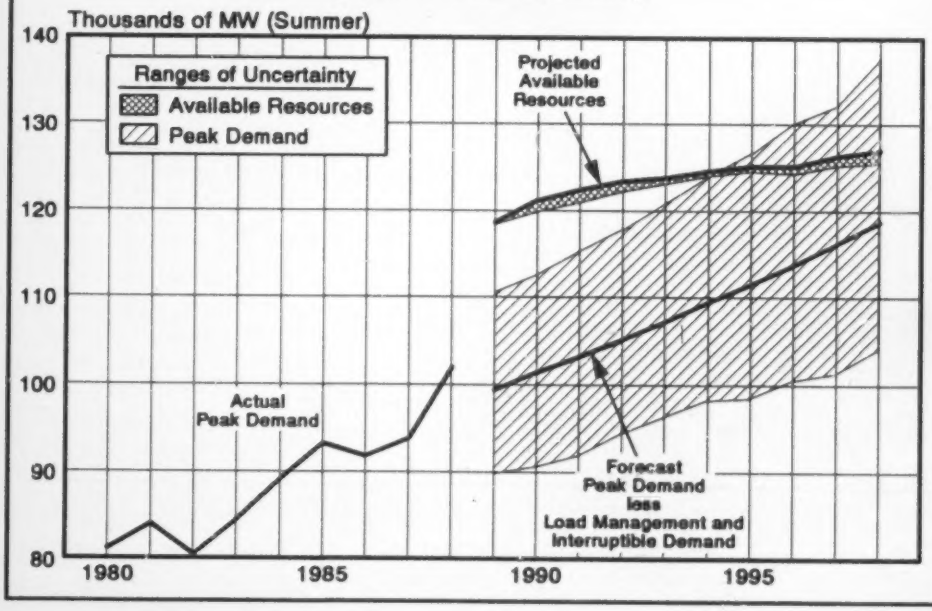
Within each Interconnection, individual utility systems are operated in synchronism with each other. This means that all the interconnected utility systems are connected by alternating current (ac) transmission lines and the frequency of the alternating current is the same at all points in the interconnected area. A simple indication of synchronous operation is that all electric clocks in an Interconnection will run at the same speed.

There are other important electrical characteristics of interconnected systems. Changes in demand or generation at any point in the Interconnection will be perceived throughout the Interconnection to varying degrees. Within limits of the transmission systems, demand at any point in the Interconnection can be supplied by generation located at any other point. Transfer of electricity from one point to another will, to some extent, flow over all ac transmission lines in the Interconnection, not just those in the direct path of the transfer.

Because of technical and economic reasons it is impractical to use alternating current transmission lines to tie the major Interconnections to each other. However, direct current facilities are used for this purpose. The ability to transfer electricity between the Interconnections is limited to the capacity of these dc tie lines, the ability to deliver electricity through the network to the tie points, and by the amount of generating capacity available at the time of the transfer.

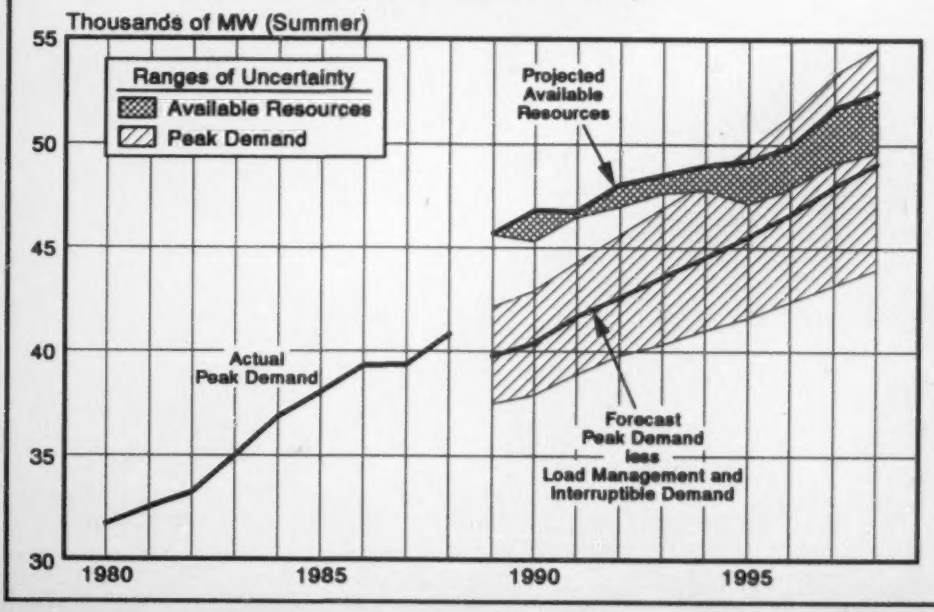
Western Interconnection Figure 10

Ranges of Uncertainty for Peak Demand and Projected Available Resources
(1989 – 1998 Forecast)



Texas Interconnection Figure 11

Ranges of Uncertainty for Peak Demand and Projected Available Resources
(1989 – 1998 Forecast)



The benefits of load management and the amount of customer demand that can be reliably and cost-effectively managed tend to be unique to each utility system. However, there are also certain drawbacks and uncertainties associated with dependence upon load management to delay capacity additions. If withdrawal from load management programs, particularly with limited notice, is allowed for commercial and industrial customers, unanticipated increases in utility peak demand could result at a time when capacity supply may already be critical.

There is also substantial uncertainty as to how much actual demand reduction will be realized at the particular time it is needed. Inconsistent demand response has already been observed in experimental and pilot load management programs.

Load management has many potential advantages, but it also has many potential drawbacks. The relative weight of each is still uncertain.

Electrical Energy Production by Fuels

The projected electrical energy production from primary energy sources in 1989 and 1998 is illustrated in Figure 14 for the United States and Canada. The U.S. and Canadian generating capacities, also segregated by fuel type, are shown in Figure 15.

Coal will continue to be the dominant fuel for electrical

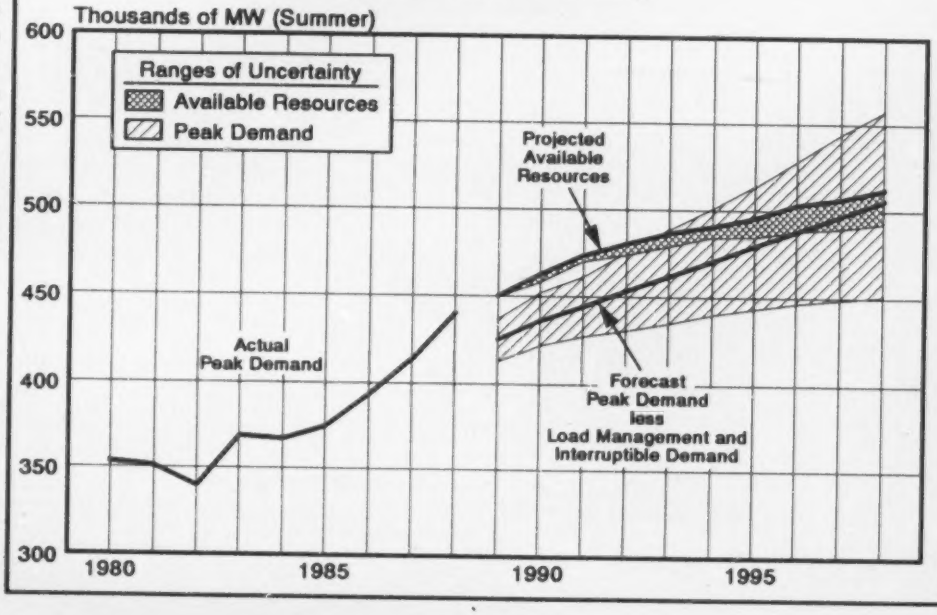
energy generation in the United States while hydro will continue to be the mainstay in Canada. Electrical energy production from non-utility generators is estimated to increase in the United States from 3.2% of total production in 1989 to 6% by the end of the assessment period and from 0.1% to 0.9% in Canada. A variety of fuels will be used in the production of electricity from NUG capacity, but natural gas is expected to be the dominant fuel.

The mixture of fuels is not homogeneous among the various Regions as illustrated in the introduction to the Regional Assessments section of the report. By 1998, reliance upon coal will vary from 87% in ECAR to 16% in NPCC. All U.S. Regions, by 1998, have nuclear capacity that generates from 40% of the electrical energy production in MAIN to 9% in ECAR. In Canada, only NPCC-Canada will generate electrical energy from nuclear, constituting 29% of its 1998 production. All Regions in Canada depend on hydroelectric capacity from 48% to 70% of their electrical requirements in 1998.

Petroleum fuels (gas and oil) are relied upon in six of the Regions with the heaviest dependence in 1998 being 33% in ERCOT, 30% in NPCC-U.S., and 27% in SPP. The heavy reliance on foreign oil by NPCC is of concern to that Region. As transmission becomes more constrained from North to South and West to East into NPCC-U.S., it may cause a further dependence on oil for this Region.

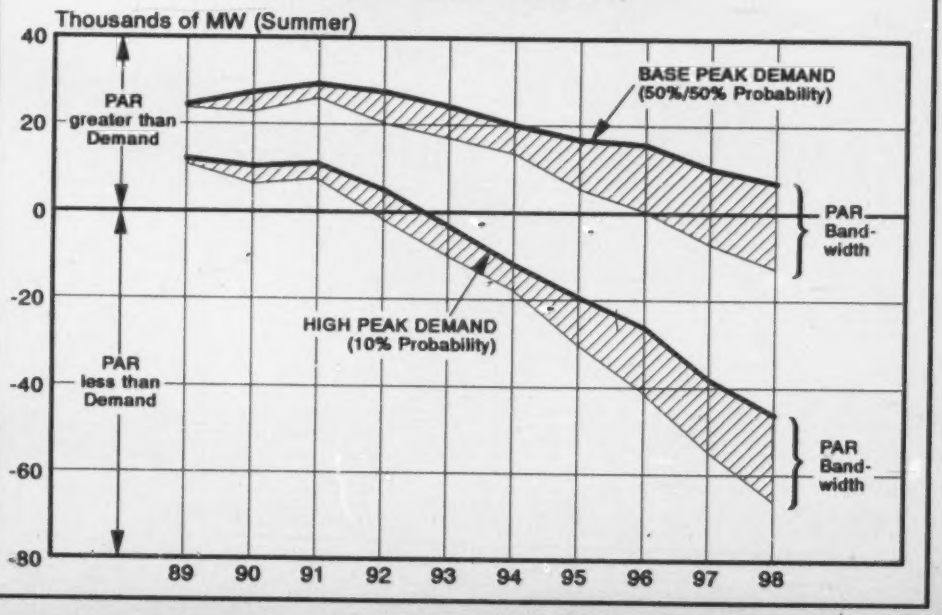
Eastern/Québec Interconnection Figure 12

Ranges of Uncertainty for Peak Demand and Projected Available Resources
(1989 – 1998 Forecast)



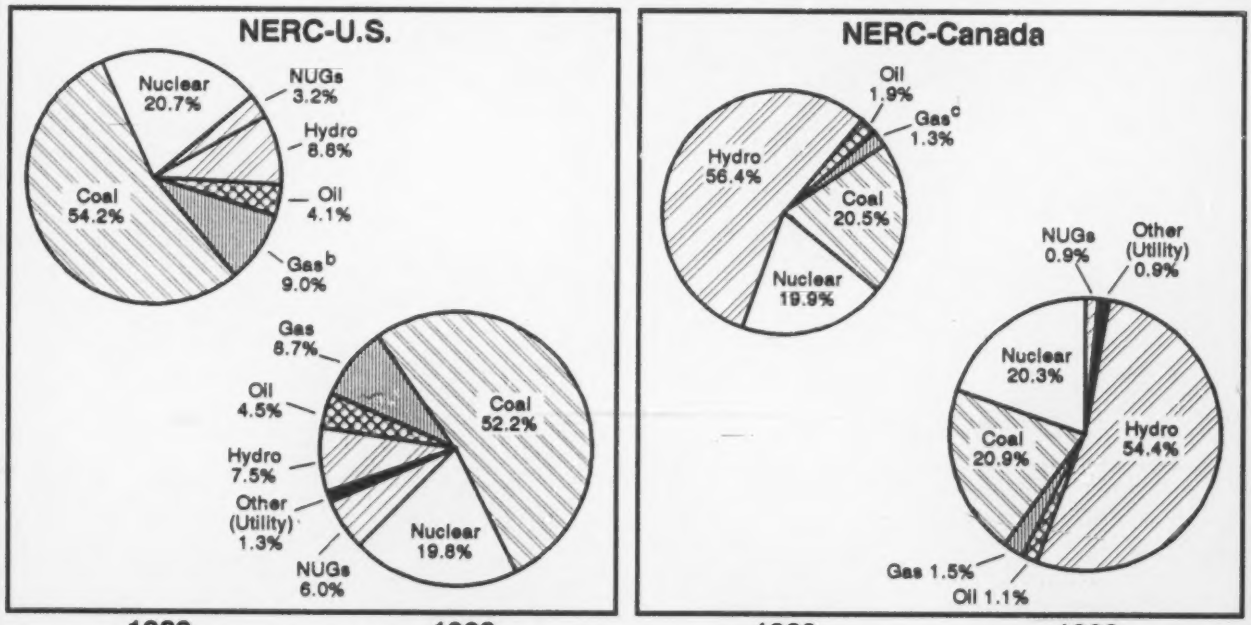
Eastern/Québec Interconnection Figure 13

Projected Available Resources (PAR) Less Probable Peak Demands
(1989 – 1998 Forecast)



Electrical Energy Production[a] by Fuel

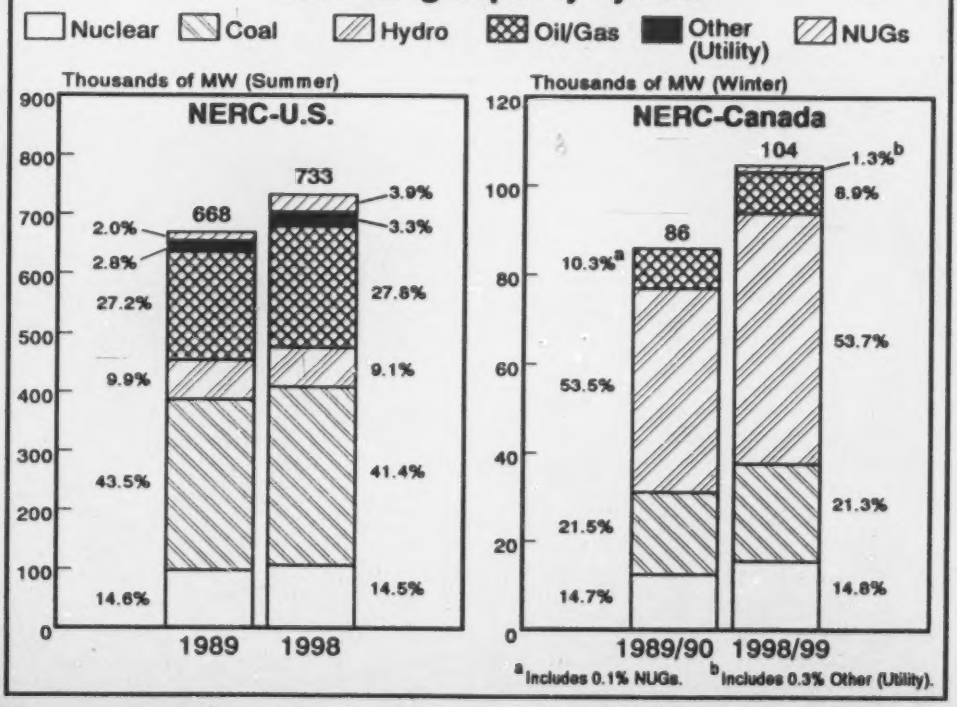
Figure 14



[a]From primary energy sources (pumped storage generation and net imports excluded).
[b]Gas includes 0.7% Other(Utility).
[c]Gas includes 0.1% NUGs and 0.2% Other(Utility).

Generating Capacity by Fuel

Figure 15



[a]Includes 0.1% NUGs. [b]Includes 0.3% Other (Utility).

Regardless of which fuel is dominant for a particular Region, utilities have recognized the need for flexibility in their generating capabilities. Market fluctuations throughout the 1970s signaled the need for utilities to intensify efforts at diversifying their fuel patterns, particularly with respect to reducing their dependence on oil and natural gas. The electric utilities' policies regarding diversification of their fuel mix are sound and essential to the reliability of the electric systems.

TRANSMISSION RELIABILITY ASSESSMENT

The existing electric transmission systems and plans for future transmission additions over the next ten years are generally judged to be adequate to reliably supply customer electric demands. However, reliability deficiencies exist in some areas where transmission facilities have not been constructed as planned or where the use of the transmission system has changed from that which was planned. Specific areas where transmission reliability is of concern are ERCOT, MAAC, MAIN, and SERC.

The complexity of operating the transmission systems will continue to increase as utilities maximize the use of existing facilities. Non-utility generators will contribute to that operating complexity. Utilities are seeking ways to deal with this complexity through improvements in monitoring, more widespread information exchange, improved control and coordination, increased and more rapid analysis, and enhanced operator training.

The future reliability of the transmission systems depends on siting and constructing new facilities in a timely manner where required. Because of the history of disincentives and delays involved with constructing new transmission, there is concern that future transmission capability will not match the need in some areas. The result could be unsatisfactory reliability due to limited simultaneous emergency transfer capability and continuously heavily loaded transmission systems in these areas.

Planned Transmission System Additions

The bulk transmission systems, 230 kV and above, have proven to be valuable and flexible resources. They enhance reliability through intraregional and interregional ties providing the capability for firm, economy, and emergency interchanges. The use of transmission systems will likely expand in the next ten years as utilities increase their dependence on remote generation sources, capacity purchases and sales, and economy energy transfers. Additions to the transmission systems will be needed in many Regions to maintain reliability while accommodating utility system growth and expanded transmission use.

At the end of 1988, the bulk transmission systems consisted of 182,275 circuit miles of ac transmission lines and 3,570 circuit miles of dc transmission lines. New transmission planned over the next ten years includes 18,760 miles of ac and 1,450 miles of dc circuits. Additions for NERC-U.S. and NERC-Canada are shown in Figures 16 and 17, respectively.

The approvals process continues to discourage plans for some major transmission additions by creating uncertainty of gaining approvals and by lengthening the lead time for building new transmission. Roadblocks to new transmission lines are presented by rulemaking actions that prohibit the development of new rights-of-way, that place unreasonable requirements on utilities to show there are no adverse environmental impacts, or that increase the cost of new transmission by setting impractical design parameters or requiring underground construction.

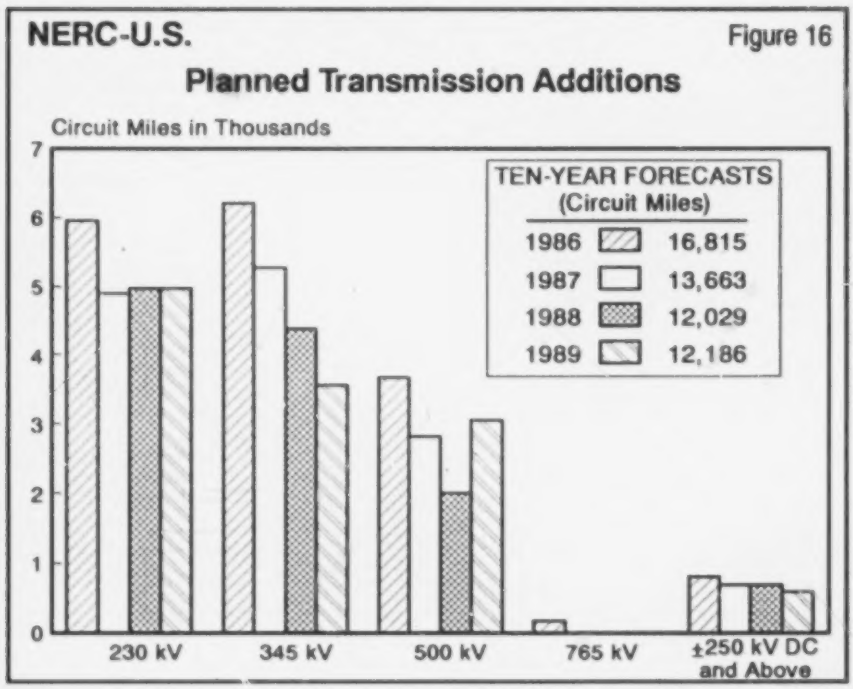
Examples of key transmission reinforcements impacted by delays are described below and summarized in Table 8.

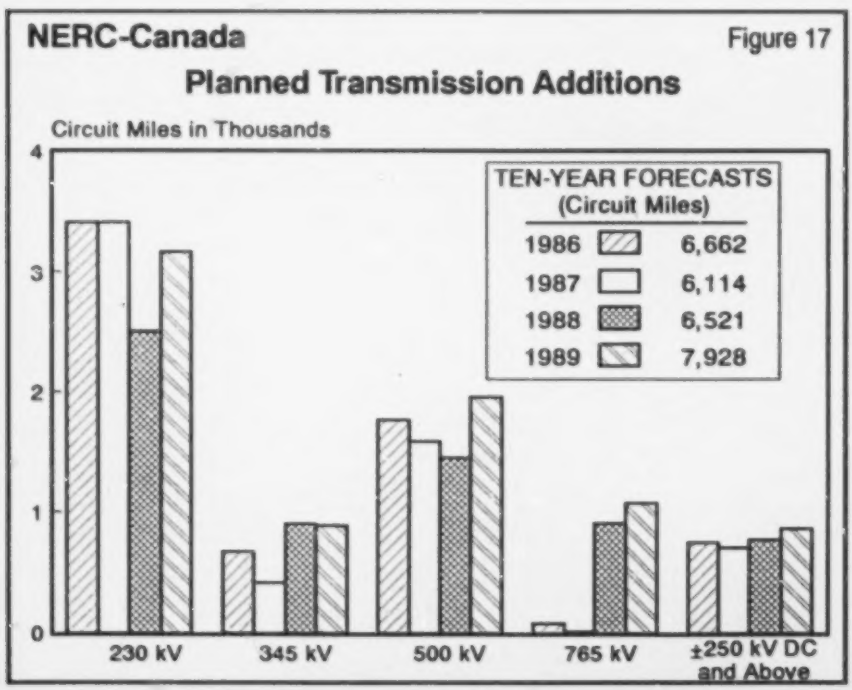
- Baltimore-Washington 500 kV Loop – Completion of the 500 kV loop around the Washington, D.C. metropolitan area, originally scheduled for the mid-1970s, is now expected in the mid-1990s. The two segments remaining for completion are the Chalk Point-Calvert Cliffs circuit and the Brighton-Waugh Chapel circuit.

  During recent zoning hearings, the issue of health effects of extra high voltage lines surfaced. The Maryland Public Service Commission reopened the certification proceedings limiting the scope to consideration of safety and health effects, if any, associated with electromagnetic fields (EMF) resulting from the operation of the proposed 500 kV lines. Continued delay of completion of the loop will reduce the reliability of the MAAC Region and neighboring Regions by restricting interregional transfer capability and reducing electric system stability margins in the Baltimore-Washington, D.C. area.

- Salem-Zenith 345 kV Line – Application for certification of the 55-mile, double circuit, 345 kV Salem-Zenith line in Texas, which has been in the regulatory certification process for over four years, was rejected due to routing issues by the Texas Public Utility Commission (PUC) in November 1986. This line is needed to increase emergency transfer capability within ERCOT, to deliver energy from remote generation, and to provide for economy energy and firm capacity transfers. An appeal of the PUC

decision resulted in a December 1987 ruling by a State District Court which ordered the Texas PUC to reexamine the findings of fact in the case. Interveners appealed the District Court ruling, but the Appellate Court affirmed the District Court decision. Intervenors have now appealed to the State Supreme Court.





• Lake Tarpon-Kathleen 500 kV Line – Construction of this line in Florida has been delayed because of a state-initiated review of EMF. The line, originally proposed for December 1987, is now indefinitely delayed. Until the line is placed in service, higher cost local generation will be operated to maintain system reliability. As area demand increases in the early 1990s, the continued uneconomic operation of local generation will become ineffective in maintaining reliability.

• City of Austin, Texas 345 kV Lines – In September 1987, the City of Austin cancelled construction of a 345 kV loop due to citizen opposition and environmental concerns. As a result, the City of Austin will not meet ERCOT Planning Criteria during portions of 1989. A short-range plan that will significantly improve Austin's reliability was approved in March 1988 and is being implemented. A long-range 138 kV transmission plan that will allow Austin to meet the Criteria was recently approved in concept by the City Council.

• Albion-E. West Frankfort 345 kV Line – The Albion-E. West Frankfort line will complete a 345 kV tie from the Gibson generating plant of Public Service of Indiana to the Central Illinois Public Service Company transmission system at West Frankfort. This will constitute the third 345 kV circuit across southern Illinois. The line is needed to reinforce the electric supply capability to a large area of southeastern Illinois. The line section was originally scheduled for completion in 1990. However, due to a lengthy regulatory approvals process, court action required before condemnation, and probable future court actions, the line is now delayed until 1992.

Table 8 — Summary of Key Transmission Reinforcement Delays

Region	Line	Original Scheduled Date	Current Scheduled Date	Voltage	Reason for Delay	Reliability Impact
MAAC	Baltimore-Washington Loop	1974	1994	500 kV	Regulatory process, EMF questions	Limited interregional transfer capability, system stability
ERCOT	Salem-Zenith	1984	Indefinite	345 kV	Regulatory certification	Inadequate transfer capability
SERC	Lake Tarpon-Kathleen	1987	Indefinite	500 kV	EMF questions	Inadequate transfer capability
ERCOT	Austin 345 kV Loop	1988	Indefinite	345 kV	Cancellation by the city council partly due to EMF questions	Inadequate supply security to Austin, Texas
MAIN	Albion-E. West Franklin	1990	1992	345 kV	Regulatory approval, land owner opposition	Inadequate supply capability to southeast Illinois
MAAC	Red Bank-Taylor Lane-Aberdeen	1990	1990	230 kV	EMF questions	Inadequate local supply, reduced area import capability

- Red Bank-Taylor Lane-Aberdeen 230 kV Line — Opposition to this 12-mile line in New Jersey has recently surfaced and threatens to delay the installation beyond the scheduled 1990 service date. The principle reason stated by those opposing the line is concern about EMF health effects. The line is required to provide reliable supply to about 300 MW of rapidly growing demand in the mid-coastal area of New Jersey. It is also part of the bulk transmission system that provides reliable supply to a much larger area in central New Jersey (over 2,000 MW). This line increases the ability of the bulk system to serve the area and helps reduce the exposure of the system to load shedding during severe operating conditions.

Adequacy of Transmission Systems

Electric utilities within each Region continually assess the ability of their internal transmission systems and interconnections with other systems to meet the objectives, including those for transfer capability, specified in their individual reliability criteria. These assessments are based on both short- and long-term needs. To complete these evaluations, Regions also participate in joint studies with adjacent Regions. These intraregional and interregional studies measure overall system strength and capability that are used to judge future transmission system adequacy.

Bulk electric transmission systems as currently planned throughout NERC are generally expected to be adequate during the next ten years. However, reliability deficiencies exist in certain areas of ERCOT, MAAC, MAIN, and SERC where transmission facilities have not been allowed to be constructed as planned or where the use of the transmission system is changed relative to the system that was planned, leaving little room for additional unforeseen simultaneous electricity transfers.

Transmission Reliability Concerns

Bulk transmission is the workhorse of the electric systems. Strong and flexible internal and interconnected systems were constructed by utilities as they developed large central-station generating plants and high capacity interconnections. Today, these systems are being used to their limits in many areas of the United States and Canada. The heavy dependence on interconnected transmission systems has resulted from utility interchange of economically-priced energy and capacity transactions to provide needed generation resources, to defer utility-constructed units, or to deliver non-utility generation to customer loads.

The capabilities of the interconnected systems will have to be expanded to accommodate the anticipated increasing needs for transmission capability. The future reliability of the interconnected transmission systems is dependent on the ability to site and construct new facilities when needed.

- Adequacy of Future Expansion Plans — A key to an adequate and reliable interconnected transmission system is its robustness or ability to respond to changing electricity flow patterns, generation and transmission equipment unavailability, and varying demands for its use without creating conflicts or reliability risks. There is concern that

USES OF TRANSMISSION SYSTEMS

The network of bulk electric transmission systems provides several functions that are vital to the reliability and adequacy of electric supply. The major uses of bulk transmission systems are to:

- **Deliver generation to load centers – Generation sites are often remote from customer load centers. Transmission systems are required to provide a reliable way to deliver electricity from remote generators to the customers.**
- **Provide flexibility for contingencies – Transmission systems and interconnections provide flexibility to handle system emergencies and uncertainties such as outages of generation or transmission equipment, construction delays, higher than expected customer demand, and fuel shortages or disruptions.**
- **Reduce installed generating capacity – Transmission interconnections among utility systems allow utilities to share generating capacity through diversity in peak demand and generator availability. Sharing generating capability required for reliability significantly reduces each utility's investment in generating facilities.**
- **Allow sharing of generation among systems – Transmission lines allow use of the most economic generation resources among utilities while maintaining reliability. Utility customers benefit because the lowest cost generation is dispatched to supply their electricity needs.**

Many interconnected transmission systems were originally designed to primarily provide reliability through emergency transfer capability assistance among utilities. In this sense, the transmission system is a generation resource in that it provides access to a large source of generating capacity.

For example, a large independent power pool may require about 35% capacity margin if it were not interconnected with other systems or Regions. But with sufficient transmission ties to available generating capacity in adjacent large systems, it may only require 25% capacity margin for the same level of reliability. The capacity value of transmission ties to the power pool is ten percentage points in this case. It is important that generation and transmission planners work together to assure the proper generation-transmission planning and operating coordination.

In the past, large capacity or energy transfers on the transmission systems were only expected to occur during critical component outages or system emergencies. However, in recent years, these same transmission systems have been routinely used for significant amounts of interregional electricity transfers driven by economics instead of emergency assistance. The transmission systems have performed this economic function quite well. The increased role of these economic transfers may well change the projections for future transmission additions.

this robustness and flexibility will not exist in the future systems.

Regulatory pressure is influencing utilities to provide only the minimum facilities needed in the short term. The result is a transmission system with heavier loadings and one that is sensitive to small system changes. Because of this, owners of transmission are becoming protective of their diminishing transmission capability margins. Devices to help direct today's electricity flows may have to be added. Also, complex special protection systems may have to be installed to solve today's problems. The result of all these issues can be a transmission system that no longer provides the desired flexibility over a range of possible future conditions.

- Interregional Transmission Capability – Interregional transmission capability may not be enough to provide flexibility to deal with changing conditions even though individual Regions and some interregional analyses indicate no problem. These analyses are generally based on non-simultaneous measurements of system capability with long-term contracted transactions between Regions modeled for the studies. Under these modeled conditions, there may not be problems. However, on the actual system, there are many short-term transactions occurring simultaneously that can sometimes create limitations far below the calculated non-simultaneous limits. Conflicts arise when the actual transmission capacity proves to be less than expected. Certain portions of the transmission system are not robust because limits are reached sooner than expected when simultaneous transactions take place. Simultaneous use is extremely difficult to consider in planning studies. Unless a robust, flexible system is provided, reliability of future interregional transmission systems may not be achieved.

- Continued Heavy Transmission Loadings – Heavy transmission system loadings are expected to continue in many areas as the need to use the systems increases more rapidly than the capability. Increased use of transmission capability will result from economic incentives for short- and long-term energy transactions. Also, the scope of use of transmission is being expanded as utilities purchase

generating capacity from other utilities or from non-utility generators. This additional use of interregional transmission capability can create conflicts with the emergency assistance transmission capability that allows utilities to minimize required installed capacity margins. As future installed capacity margins are projected to become small in some areas, this conflict between different uses of the transmission network becomes more critical.

An example of a heavily loaded transmission network is the area near the interfaces of the ECAR, MAAC, and SERC Regions. Utilities in this area developed a Reliability Coordination Plan because of heavy loadings of the transmission systems and the potential adverse impact on reliability. The Reliability Coordination Plan is an operating strategy and procedure aimed at maintaining reliability margins at these interfaces. Although the program did not have to resort to load shedding, it was in effect for 81 events during 1988 summer. This close cooperation among these parties has been instrumental in maintaining system reliability while maximizing use of the transmission systems.

Continuous heavy transmission loadings affect reliability because of the increased exposure to potentially severe consequences should unexpected generation or transmission facility outages occur. Systems are being operated within the same accepted reliability standards as before, but they are at or near their transmission capacity limits for longer periods of time. This increases the likelihood of severe consequences resulting from equipment failure, human error, or low probability events such as the loss of multiple facilities.

Many of the disturbances reported in NERC are a result of near simultaneous loss of two or more key facilities at the time of heavy system loading. An example is the separation of Peninsular Florida from the rest of SERC in November 1987 when two 500 kV lines tripped out of service while loaded to over 2,200 MW. In this case, 2,250 MW of customer load was automatically shed (removed from service) due to the capacity deficiency.

Heavy loadings on transmission systems affect reliability in another way by inhibiting the removal of facilities from service to perform maintenance and testing. If not properly maintained, performance of equipment can be degraded resulting in more frequent equipment forced outages or improper operation. When transmission lines are out of service for maintenance, the loading on the remaining system components will be higher than normal increasing the risk of a major system disturbance.

- Obsolete Transmission Facilities — Obsolete substation equipment can adversely affect transmission system reliability. As substation equipment ages, repair parts are more difficult to acquire or can take a long time to manufacture. The extended repair times for older substation equipment creates increased exposure to multiple facility outages as well as adding an additional layer of complexity for the system operator. These conditions can result in unusual system performance and in disturbances that may be more frequent and more severe than normally expected.

  Utilities are dealing with this aging problem in several ways to minimize the effects on reliability. Spare equipment is available for critical facilities. Some utilities are partners in programs that provide equipment for emergency assistance to one another, while others have started studies that will provide a better insight into the exact nature of the aging effects on various transmission system components. This information will enable all utilities to assess the seriousness of aging and to select candidate facilities for refurbishment in a logical sequence.

- Transmission for NUGs — In a few instances, transmission lines have been built by non-utility generators (NUGs) to deliver their output to the utility systems. This poses no particular problem when these lines are radial to the utility network. However, if the lines are in parallel with the utility system, problems can arise. Close coordination, joint planning, and operating arrangements are required to assure that any transmission, not a part of a utility system, will not cause adverse effects on overall utility system operations and reliability.

Regional reliability concerns regarding transmission service and deregulation are explored in the "Transmission Service and Deregulation" portion of the "Reliability Issues" chapter.

Increased Operating Complexity Concerns

Utilities are actively pursuing ways to better deal with the increasing complexity of operating the electric systems. Complexity in operations can have an adverse effect on reliability because it becomes more difficult to analyze and control the systems and to schedule transactions while staying within reliable operating limits. Improvements in system monitoring, data exchange, communication of plans and procedures, on-line security analysis, joint planning and operating studies, and operator training are some of the many areas continuing to be addressed in an effort to adapt to the changing nature and growth of the electric systems and still maintain adequate reliability. Some operating complexities of particular concern include the following:

- Special Protection Systems – Complexity is increased through the use of special protection systems (SPS) or remedial action schemes. These systems are usually implemented so that more electricity can be delivered across a transmission system. SPSs are highly sophisticated schemes that depend on multiple data inputs, good communication channels, and reliable equipment. Due to their complexity, they sometimes misoperate. Misoperation under heavy electricity transfer conditions may have severe consequences. Operators must be alert to the conditions that create the need for SPSs and the consequences of their misoperation.

  Special protection systems have their place in an electric utility system if they are properly designed and applied. NPCC has recently approved guidelines regarding the application of SPSs. The NPCC guidelines define three types of SPSs based on their transmission system impact, and specify design requirements for each type. WSCC also has established criteria governing the application of SPSs on its systems.

- Parallel Path (or Loop) Flows – Because of the nature of ac transmission systems, energy transactions between two systems can cause flows in parallel transmission paths in other interconnected systems not directly involved in the transactions. These flows make it difficult to analyze system capability and performance because the sources of these transactions are not easily determined. The wide range of transaction possibilities creates a myriad of conditions to study, monitor, and control.

- Voltage and Stability Limits – Voltage and stability limits become more significant for heavily loaded transmission systems particularly as electricity is transferred over greater distances. These limits are also more difficult to monitor and control. With a stressed or heavily loaded transmission system, voltages may be well within acceptable limits for normal conditions. However, a single facility outage or contingency due to equipment failure or misoperation could cause immediate widespread and severely reduced system voltages. Voltage problems are especially critical because system operators may not have time to make adjustments before a collapse occurs. Three of the five 1987 disturbances analyzed in the NERC *1987 System Disturbances* report exhibited low voltages that resulted from transmission outages during heavily loaded conditions.

  To make the situation worse, the critical facility failure or misoperation could be remote from the utility that would experience the largest voltage decrease. This type of situation could go unrecognized until a disturbance occurs, unless planning studies uncover the problem and monitoring and communication procedures are implemented for system operators. Coordination in planning and operating the electric systems is vital to maintaining adequate system reliability especially when long-distance electricity transfers are common. The operating procedures implemented jointly by power pools in NPCC and MAAC to monitor transmission systems that can be impacted by imports from Canada and keep them within safe loading limits is an example of this coordination.

- Addition of Control Capabilities – In attempts to minimize parallel path flow effects and to maximize the use of one's own transmission, utilities are adding power flow control devices such as phase angle regulators, series capacitors, and series reactors. These devices help to redirect power flows but may not eliminate the problems. Instead the problem may be moved to another part of the Interconnection. Addition of these devices and their proper operation require close coordination of their operation as well as good communications among operators. These devices add to the complexity of analyzing and operating the system reliably.

- Increased Communications and Control – As electric system limits are approached or exceeded, the electric system operator must make adjustments to maintain or reestablish reliable conditions. The operator must deal with many concerns when making these adjustments, such as contract terms, economic impacts, emergency capability of facilities, and transmission loadings. It is no longer adequate to only monitor one's own system. Long distance transactions and tightly interconnected systems require knowledge about key facilities from surrounding

SPECIAL PROTECTION SYSTEMS

Special Protection Systems (SPSs), also known as Remedial Action Schemes, are designed to perform system protection functions other than the isolation of electrical faults. Typically SPSs trip loads, generators, or additional transmission facilities. SPSs are installed to operate in contingency situations to permit higher levels of electricity flow on the transmission system in those instances where additional facilities cannot be built, or have been delayed. They may be used to maintain system stability or control loadings on critical facilities immediately following a system disturbance or other abnormality on the system. SPSs may also allow higher electricity transfers and the use of more economic generation. However, they expose a system to greater reliability risks since the integrity of the system depends on their correct operation.

systems so operators can make well-informed decisions. The many different transactions and their interactions increase the importance of good communications among neighboring systems for monitoring, evaluating, selecting, and implementing proper system adjustments. An example is the formation of the Inter-Utility Data Exchange Committee (IDEC). This is an eight member group that has agreed to establish the capability to exchange operating data using computer-to-computer links. It is to use standard and expandable protocol, software, and hardware. Also, NERC has established a task force to investigate the use of the Manufacturing Automation Protocol/Technical & Office Protocol (MAP/TOP) project for utility computer-to-computer data exchange applications.

RELIABILITY ISSUES

Demand Exceeding Forecast

In the last few years, actual peak demands in many Regions have been consistently and substantially above forecast. Recognition of this trend is needed now to avoid risk to electric supply adequacy.

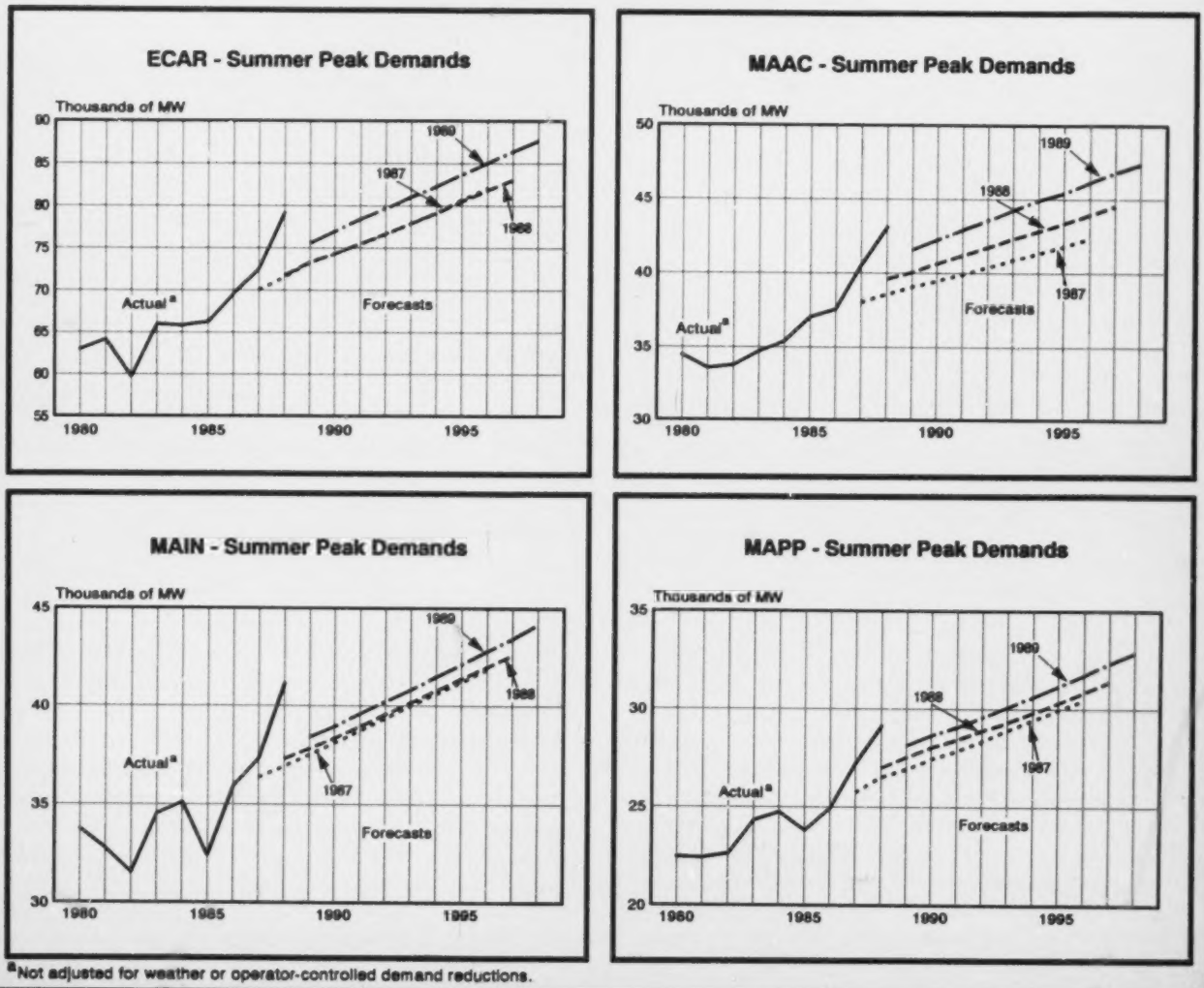
Regional Demands Are Exceeding Forecasts

Figure 18 tells an important story. Actual peak demands have been consistently and substantially above forecast. For six consecutive years, the actual peak demand in the MAAC Region has exceeded its forecast made just one year earlier. Five of nine NERC Regions have exceeded forecast for the last three years.

In 1987, eight out of nine Regions underestimated their peak demand. In 1988, in every single NERC Region, nine out of nine, the forecast was exceeded. The 1988 forecast of peak

Figure 18

Actual Versus Forecast Peak Demands for Several NERC Regions



[a]Not adjusted for weather or operator-controlled demand reductions.

demand in MAIN was exceeded by 10.3%, MAAC by 8.9%, and MAPP by 7.8%. The total underestimation for all Regions was over 31,000 MW.

There will always be differences between actual demand and forecast, so why raise this issue? There are three important observations to consider. First, the forecasts have been consistently low, not a balanced mixture of half over and half under. Underestimating demand for three or more consecutive years is a disturbing trend. Over the last three years, 81% of the regional forecasts of the next year's peak demand have been low. Second, the forecasts differ from actual by a significant percentage. MAIN, for example, forecast its 1988 growth at 2.6%, but actually experienced growth of 9.8%. Third, the actual NERC-U.S. peak demands are not only exceeding the base forecasts traditionally used for planning, but are also reaching levels outside the 80% probability bandwidths.

All this clearly identifies a trend of peak demands exceeding forecasts, most prominently within the Eastern Interconnection, where capacity to serve customer demands is already a concern.

Why?

In several Regions, extremely hot summers are at least partially responsible for demands exceeding forecasts. This is because forecasts are typically based on "normalized" temperatures for a given area. The effects of above normal temperatures are generally intended to be covered by capacity margin allowances, not by increasing peak demand forecast. If actual temperatures exceed "normal," demand will likely be higher than forecast, in some Regions by as much as several hundred megawatts per degree. It is difficult in some NERC Regions to assess temperature effects partly because temperature extremes may not occur uniformly across the Region. In the MAAC Region, information is available to assess the extent temperature extremes were responsible for the 1988 peak demand being 8.9% over forecast. This data shows that only about half of the excess demand could be attributed to temperature extremes. In MAAC, and in other NERC Regions, there are a number of additional factors that may be significantly affecting the likelihood of demand exceeding forecast.

- Could some of this unanticipated increase in peak demand and net energy for load be due to the continuing strong economy? This possibility has been supported by sustained consumer purchasing and business expansion. Higher than forecast growth has occurred in all sectors – industrial, commercial, and residential. Anticipated recessions have not materialized. To the extent the effects of recessions have been included in the forecasts, the forecasts have underestimated future demands.

- Are real price declines in electricity, and the diminishing influence of earlier price increases, also contributing to continued growth? These perceived changes in electricity prices also affect the relative competitive position of electricity to alternative energy sources. A question should be raised as to whether these changes in both the real and relative prices of electricity are being fully recognized in the forecasts.

- Is the price of electricity being kept artificially low as a result of disallowances of capital investments, and if so, is this contributing to underforecasting? Utility forecasts are based on price factors associated with anticipated recovery of utility investments. Will demand exceed forecast if the price of electricity is reduced by unanticipated disallowances?

- Are there long-term effects on future peak demands as a result of recent weather conditions of hotter than normal temperatures? What are the future effects of additional air conditioning and cooling equipment installed as a result of the recent weather anomalies? Are these factors being fully reflected in the forecasts?

- The forecasts of future peak demands are showing a significant amount of load management to reduce peak demands. Are these estimates of load management being achieved or are they overly optimistic?

- As discussed in the "Public Policy Disincentives" chapter, could disincentives be influencing the forecasts of future demand, so as to avoid showing a need for additional generating capacity?

Impact on Reliability

During the late 1970s and early 1980s, utility forecasts consistently overestimated peak demands. The result was larger capacity margins. Utilities responded by delaying or cancelling planned generating units and by mothballing less efficient units. Installed generating capacity was adequate and did not adversely affect reliability. Historical data indicates that it took about ten years for forecasts to reflect the declining actual growth rates. The current situation, however, is reversed. Peak demands are exceeding forecasts. If demand continues to grow faster than forecast, reliability can be adversely affected.

If it takes ten years for forecasts to reflect actual demands, utilities will not be planning for adequate generating capac-

ity. A comparison of the ten-year regional forecasts for 1988-1997 with actual peak demands in the summer of 1988 shows that three NERC Regions have already experienced peak demands that were not forecast to occur until 1994. This puts these Regions six years ahead of their 1988 forecast and may put them up to six years behind in their capacity planning process. If these trends in future peak demand levels continue, several Regions may be seriously short of capacity. An example of such a shortfall is the MAAC Region. For the next three years, MAAC capacity resources are projected to be below the level required to reliably supply recently increased peak demand forecasts. This situation has occurred because of peak demand exceeding forecast for several prior years combined with the inability to make sufficient short-term corrections to installed capacity plans.

Such a situation limits available supply options for meeting future capacity needs to only the most expedient options such as purchased capacity from others, if available, and combustion turbines. However, if the problem of demand exceeding forecast continues to be widespread, capacity for purchase may not exist, and lead times for combustion turbines could extend beyond the time when needed. The impact on reliability could manifest itself in many of the forms mentioned in the "Reliability and What it Means to the Customer" chapter, including the capacity shortage situation currently existing in Argentina.

Utilities must respond to the trend of peak demand exceeding forecast. The time to respond cannot wait the ten years it took during the era of overforecasts. Recognition of this trend is needed now to avoid risk to electric supply adequacy.

RELIABILITY ISSUES

Economy Versus Reliability

In recent years, external forces have caused economic goals to encroach upon the goal of adequate bulk electric system reliability. If the proper balance between economy and reliability is not maintained, this trend could lead to inadequate reliability and ultimately higher cost to the customer.

Economy-Reliability Balance

Many factors are considered when planning and operating bulk electric systems. Among the more important factors that are assessed by both utilities and public policymakers are reliability and economy. Since these factors can work in opposition to one another, it is important that reliability and economy be properly balanced using consistent and objective evaluation criteria. This balance can only be adequately maintained when economic optimization is achieved while reliability is maintained or improved.

The following examples help illustrate some of the important issues to be faced in the future in which maintaining the balance between reliability and economy is of concern.

- Operating Closer to System Limits – With the technology now available to utility planners and operators, electric systems are able to operate closer than ever to the edge of their technical capabilities. Operating in this fashion can result in substantial economic benefits for both the utility and its customers.

  Improved control and monitoring technology have made it easier to estimate how close the system is to its limits. However, operating an electric system at the limit of its capabilities exposes that system's customers to a greater risk of widespread service interruption should an equipment outage or system emergency develop. The consequences of a misoperation or equipment failure are often more severe the closer a system is operated to its capacity limits. A combination of two or three simultaneous equipment outages may not cause a major problem for a system that is being operated under lightly loaded conditions, but the same outages may have catastrophic results when the system is heavily loaded and has limited margins.

  With modern society's dependence on a reliable electric supply, the consequences of a widespread service interruption can be staggering from both economical and societal standpoints. When assessing the economic benefits of operating a system closer to the limit of its capabilities, it is critical that the potential cost of inadequate reliability be carefully weighed.

- Economy Energy Transfers – Incentives to benefit from economy energy transactions should not result in sacrifices to bulk transmission system reliability. Throughout all Regions, utilities strive to make optimal use of their existing transmission systems for economy energy transfers by purchasing lower cost economy energy when available. However, when transferring economy energy, there is a risk of depleting transmission capability that may be needed for system emergencies. Those responsible for balancing the reliability of the network against economical operation must ensure that use of the transmission network for economy transfers is not allowed to encroach on the primary purpose of interconnected system operations – reliability.

- Transmission Construction for Contract Path – System economics often justify the use of transmission facilities among interconnecting utilities to establish "contract paths" for interchange transactions. In many instances, these facilities carry only a small fraction of the transaction, the balance of the transaction utilizing facilities in other systems.

- Reduced Maintenance – Near-term economic pressures, generated both internally and externally, typically mandate significant cutbacks in maintenance budgets and staffing. Cutbacks in the electric utilities may result in greater risk of equipment failures which could affect not only the utility owning the equipment and its customers, but also other interconnected systems. It often takes many years for the full effects of reduced or delayed maintenance to become apparent. Likewise, once increased equipment outages and inadequate reliability due to reduced maintenance appear, it often takes many years to restore reliable operation. It is important when evaluating the priorities on the allocation of limited financial and human resources that the long-term reliability and economic impacts be properly balanced.

- Capacity Purchases – The purchase of generating capacity from either utilities or non-utility generators in lieu of the construction of new generation facilities is often viewed as an option that offers substantial benefits to both buyer and seller. However, a capacity purchase does not usually add

to the total capacity within an interconnected network. Rather, it simply transfers capacity responsibility to another party.

In the course of evaluating the economic benefits of capacity purchases, buyers should be aware that over-dependency on capacity purchases may expose the purchasing utility to reliability problems. Such problems may be caused by a variety of reasons including transmission system limitations, or the possibility that the seller may be unable to fulfill the contractual obligation to provide service to the buyer. The purchase of capacity from remote locations may also reduce transmission capability which would otherwise be available for system emergencies. Simply stated, the purchase of capacity places additional risks on the purchasing system. These risks must be carefully evaluated in determining the proper balance between the reliability and economic benefits of capacity purchases.

- Demand Management – At many utilities the use of demand management, including both conservation and direct control load management programs, has been found to offer potentially significant economic benefits. A megawatt of demand management is often considered to be a suitable replacement for a megawatt of additional generating capacity. A concern to many utility planners and operators is the fact that a megawatt of demand management is not equivalent to a megawatt of new generating capacity.

  Unlike generation, demand management programs fail to provide reactive power for maintaining system voltage. Voltage collapse due to insufficient reactive supply is becoming an increasing concern within the Regions. It can occur quickly without warning or time to respond.

  Many demand management programs involve load reductions which are only available during times of peak demand, or for just a few hours each year. On the other hand, a megawatt of generating capacity is nearly always available to assist the owning utility or other interconnected utilities during normal and emergency operations. Changes in customer attitude that can reverse the effectiveness of demand management programs at any time are also of concern. While customers may readily purchase large quantities of interruptible service from electric utilities during periods when capacity margins are high, and service is interrupted rather infrequently, they may quickly decide to convert back to firm service if capacity margins become critical, and the number of interruptions increases. These types of considerations should not be overlooked when assessing the balance between the economic and reliability benefits of demand management.

- Remedial Measures – The use of remedial measures, such as special protection systems (or remedial action schemes) and complex operating procedures, as a means of deferring the construction of new transmission facilities often has economic benefit. However, utilities that are increasing their dependence on remedial measures should weigh carefully the impact of their complexity and the consequences of their misoperation. Typically, failure of remedial measures has far more severe consequences than the failure of a transmission facility component. The probability of misoperation and the severity of the consequences of misoperation are important aspects of assessing the balance between economy and reliability. These issues are specifically addressed in regional planning and operating guidelines where use of special protection systems and remedial measures are utilized heavily, as in WSCC and NPCC.

For each of the above concerns, the complexity of properly balancing economy and reliability is a difficult assignment. Utility planners and operators must continue their efforts to identify out-of-balance situations and to encourage the understanding and support of policymakers and their customers in restoring balance.

RELIABILITY ISSUES

Public Policy Disincentives

Public policy decisions at the federal, state or provincial, and local levels have created major disincentives to the planning and construction of utility generating capacity and transmission reinforcements. Many utilities today are reluctant to undertake the financial risks associated with commitment to a large construction project for fear that certain expenditures will be disallowed in hindsight regulatory reviews.

Utilities have responded to these disincentives by moving toward a number of non-traditional resource options as a means of providing electric service. Each of these options, however, has its own uncertainties and limitations. Heavy reliance on non-traditional resource options may degrade the future reliability of electric supply.

Concept of Regulation

The electric utilities in the United States and Canada operate under a blanket of changing and sometimes conflicting federal, state or provincial, and local regulations. All major projects proposed by electric utilities are subject to review and approval by various governmental agencies. The objectives of regulation are to assure that:

- The needs of all electric customers are served in a reliable and environmentally acceptable manner. Electric utilities have a legal obligation to serve within their designated franchise area.
- Electric utilities are allowed to earn a reasonable rate of return on their investment to attract the capital necessary to continue to supply the needs of electric customers.

The goal of both the electric utilities and the regulatory agencies involved is, and has always been, to accomplish the above objectives while keeping electric rates for customers as low as possible.

Regulatory Disincentives

In recent years, the regulatory emphasis has been focused on keeping electric rates low in the short term. This creates a powerful financial disincentive that can adversely impact reliability in the longer term. Utilities are reluctant to commit to a major long-term project because of the associated financial risk. The current approach to rate setting appears to require utilities to bear the risks of so-called bad investments, while denying them the incentive benefits of so-called good investments, where in most cases the characterization of the investment is determined by hindsight analysis.

Examples of financial disincentives include:

- Disallowance of recovery of costs associated with construction work in progress – A large number of regulatory agencies exclude the costs of construction from utilities' rates until completion of the projects. This exposes utilities to grave financial risks should a project be unduly delayed. For example, as a result of the delay in the operation of the Seabrook nuclear unit, the Public Service Company of New Hampshire, which by state law is barred from recovering construction work in progress costs, has been driven into bankruptcy.
- Disallowance of recovery of costs associated with projects canceled prior to completion – Regulatory treatment of the sunk costs associated with projects that have been canceled range from full recovery in some instances to full disallowance in others. For example, in a case recently affirmed by the U.S. Supreme Court, the Pennsylvania Public Utility Commission disallowed recovery of all of the approximately $50 million of capital investments by Duquesne Light Company and Pennsylvania Power Company on generating units that were prudently canceled.
- Disallowance of recovery of costs associated with completed projects – Through the use of after-the-fact prudency reviews and hindsight analysis, the trend is for regulatory agencies to disallow an increasing percentage of project costs. An assessment of regulatory treatment of costs associated with nuclear generating capacity completed since 1983 indicates that on average some 16% of the costs of these units was disallowed, but that in an extreme case, approximately 50% of the costs associated with Gulf States Utilities' River Bend plant were disallowed.[a]

More recently, in the case of Illinois Power Company's Clinton power station, the final order issued by the Illinois Commerce Commission (ICC) contained a prudence disallowance of $666 million, which is more than 40% higher than the disallowance recommended by the Commission's own auditors. Furthermore, the ICC's final rate

[a] *"An Analysis of State Regulatory Treatment of Recently Completed Nuclear Power Plants," report prepared for Schiff, Harden & Waite, by Theodore Barry & Associates, 1989.*

order also concluded that only about 27% of Clinton's generation is needed – or in regulatory terms "used and useful," i.e., the ICC disallowed a return to stockholders on 73% of the plant.

Orders such as these provide disincentives to installing capacity that may be needed for reliability.

Other public policy actions are also adversely affecting the reliability of electric supplies. A number of issues can be cited:

- Regulatory Delays – The regulatory process takes time and reasonable allowance for this is included in utility planning. However, when the process is delayed and decisions are not rendered on a timely basis, there is the risk that key facilities may not be in service when needed. Long lead times magnify the impact of uncertainties and factors beyond the control of utilities.

  For example, regulatory delays contributed to the fact that the Long Island Lighting Company was just recently granted a full operating license for the Shoreham nuclear unit some 21 years after the initial request for a construction permit was requested.

- Inconsistent Public Policies – Inconsistent public policies make electric supply planning for the future overly complicated. Utilities must be able to anticipate with reasonable certainty what the regulatory and legislative requirements will be and how they will be applied.

  Consistent rulings on individual projects from initial authorization to completion and operation are critical. Changes or inconsistently applied policies cause delays and ultimately increase costs to electric customers, and lower reliability.

  New York State's plan to dismantle the $5.5 billion Shoreham nuclear plant on Long Island is possibly the most extreme example of this problem.

- Overlapping Jurisdiction – Major utility projects often require the approval of federal, state or provincial, and local agencies. When the findings of these agencies conflict, unnecessary delays occur leading to higher costs and the risk of inadequate system reliability.

  For example, conflicts between the states of New Hampshire and Massachusetts have prevented the long-completed Seabrook nuclear unit from operating. As a result, this much needed generating resource is currently unavailable to capacity-tight New England.

Utility Strategies

The general reaction of electric utilities to these disincentives has been to adopt strategies to avoid large capital expenditures for major projects, especially large generating units. Most utilities have shifted toward increased reliance on other resource options, such as:

- Demand management programs, including conservation, load management, and interruptible demands,
- Capacity and energy purchases from other electric utilities,
- Enhanced maintenance programs for older utility generating units,
- Combustion turbines and other small, less economic units, and
- Non-utility generators.

While each of these options has a place in utility plans, each has its own uncertainties. Modern society is so dependent on an adequate and reliable electric supply that no option should be foreclosed, including large utility generating units. In general, the future reliability of electric supply would best be served by expanding rather than limiting options and by maximizing rather than restricting flexibility.

Restoring Future Planning Flexibility

To restore flexibility in dealing with the uncertainties of future electricity requirements, a new "regulatory compact" among the electric utilities, legislators, and regulatory agencies needs to be established.

Issues that need to be addressed include:

- Recognition that the growth in electric demand is dependent on many factors outside of the control of electric utilities, and that no forecasting methodology can precisely identify future requirements. The real societal costs of underestimating demand need to be factored into considerations regarding cost recovery for "unnecessary" capacity.
- Reduction of project lead times. Utilities, public policymakers, and customers would all benefit if lead times could be shortened. The likelihood of having either too much or too little capacity would be significantly reduced if the decision for project commitment were timed closer to the actual point of need.
- Recognition of the uncertainties and limitations associated with non-traditional means of satisfying demand – particularly, non-utility generation and demand management. The long-term availability of these options is unknown and over-dependence on such options represents an unquantified risk to future reliability.

The adequacy of resources, considering both supply-side and demand-side options, is growing serious in some areas. Now is the time to take corrective actions.

RELIABILITY ISSUES
Transmission Service and Deregulation

Deregulation and the degree to which utilities may be required to provide transmission service for others are issues which potentially threaten future electric system reliability by increasing transmission system loadings, reducing transmission capability margins, and increasing coordination problems. Transmission systems were not designed to provide unlimited transmission service for all parties. It is imperative that any future policies regarding use of the transmission systems recognize the need to maintain adequate electric system reliability.

All participants utilizing the transmission systems must adhere to electric utility accepted planning and operating policies and practices designed to maintain electric system reliability as described in the NERC Policies, Criteria, and Guides.

Transmission Service

The bulk electric transmission systems are critical to providing reliable electric service and in general are owned and operated by electric utilities. They were not designed to accommodate unlimited and random use by non-utility generators or other utility systems. The term "transmission service" as used in this chapter is intended to mean use of the bulk electric transmission systems for wheeling transactions.

In today's evolving era of deregulation and competition, there are ever-mounting pressures to operate electric systems to achieve greater cost savings. Suppliers of higher cost electricity are increasingly motivated to curtail expensive generation and replace it with lower cost generation purchased from other suppliers. Moreover, some large customers served by utilities with comparatively high rates, often the result of geographical location, are seeking to use the interconnected transmission network to obtain electricity from lower cost suppliers.

In providing transmission service, a utility's transmission lines would be made available to other utilities and non-utilities for buying and selling electricity. Use of the transmission systems by an increased number of entities poses a potential threat to future electric system reliability. The degree of transmission service to be provided by the utilities has not been clearly defined and could foreseeably range from the carefully controlled manner in which the electric transmission systems are operated today to an entirely open policy requiring that transmission service be provided for any entity involved in buying and selling electricity.

The degree to which a supplier is able to use the transmission network may help to determine that supplier's level of competitiveness with other suppliers. There is growing pressure to stimulate increased competition through deregulation and increased use of the transmission systems which may simply increase costs to some customers while decreasing costs to others.

Potential Reliability Effects

The operation of electric utility systems cannot be driven solely by economic considerations. Reliability is an essential consideration. Frequently reliability and economics work in opposite directions. Efficient operations and resource management are long-standing goals of the electric utilities. In concert with these goals, electric utilities are responsible for providing adequate and reliable facilities to ensure that electric supply does not fall short in meeting their customers' demands for electricity. Under the deregulation concept, conflict over who derives the benefits from existing and new generation and transmission facilities will hinder the planning process as well as day-to-day system operations.

The major reliability implications of increased transmission service and deregulation include:

- Increased Transmission System Stress – The capability of the transmission system, or the maximum amount of electricity that the system is capable of reliably carrying, is a function of numerous technical constraints. Increased transmission use resulting from deregulation and competition will naturally tend to drive transmission loadings higher for longer periods of time, squeezing existing transmission system margins. The reduction or elimination of transmission margins may lessen the ability of the transmission network to accommodate heavy transfers of electricity under emergency conditions, and as a result reliability could suffer.

- Increased Coordination Problems – As an increasing number of transmission system elements are stressed over extended periods of time, simultaneous transfer limits will be encountered more frequently posing serious coordina-

HIGH VOLTAGE AC ELECTRICAL TRANSMISSION SYSTEMS

The high voltage alternating current (ac) transmission systems or electrical networks presently used for the transportation or "transfer" of electricity are fundamentally different from transmission or transportation systems used for the movement of commodities or products of commerce. This is because – unlike gas or oil in pipes, grain in railroad cars, traffic on the highway – electricity is not readily routed over specific transmission paths on the ac network in place today. Electricity must be produced on demand and cannot yet be economically stored.

In gas transmission systems, oil pipelines, railroad or highway systems, the "flow" in any segment or along any route can be directly controlled by valves, gates, or traffic lights. When a transfer of electricity is made, it generally cannot be directed down certain transmission "paths" to follow pre-determined routes. Rather, the distribution of electricity flow in each path from generation source to the area of need, or customer demand, is solely a function of the electrical characteristics of the transmission lines and transformers in each path relative to other paths in the network. That is, electricity will use, to varying degrees, all available transmission line "paths" between two areas in a system to effect a transfer since electricity follows the immutable laws of physics, rather than human laws or contract paths.

Because of the number of components and physical size of the interconnections in North America, the number of electricity flow patterns possible is almost infinite. In addition, the interrelated configurations of generation and transmission lines are constantly changing. This, combined with the instantaneous variations in customer demand, causes the pattern of electricity flow to change at every instant.

Since the flow of electricity cannot be made to readily follow pre-determined paths, and since the pattern of flow on the transmission systems or networks is constantly changing, it is not surprising that the capability of the transmission system to transfer electricity from one point to another is not easily defined. In fact, the capability cannot be specified by a single value. Like the pattern of flow on the network itself, the capability to transfer electricity changes continually.

While "transfer capabilities" between one system and another are often quoted, it is understood by those who determine them, and those who use them, that these capabilities are approximations for a specific set of conditions and not firm values that apply at all times. Therefore, a published "transfer capability" should be regarded more as a typical or average value. The actual capability at any moment may be considerably higher or considerably lower.

tion and control problems. It may be virtually impossible to identify those transactions that are creating transmission loading problems at any given time. Increased operating complexity will place greater demands on operating personnel. Should an operator error occur, the consequences could very likely include widespread interruption of customer service. Increased competition resulting from deregulation may lead to reduced cooperation and communications among utilities at a time when coordination will be needed most to maintain reliability.

- Increased Parallel Path (or Loop) Flows – Electricity does not flow entirely over the transmission lines defined by contracts between buying and selling entities. Electricity flows over the paths of least resistance in accordance with the laws of physics. Consequently, some of the contracted electricity may flow on parallel transmission paths through third-party systems that are not participants in the contract. To avoid transmission overloads resulting from excessive parallel path flows, third parties could lose the ability to use a portion of their transmission systems for their own purposes such as economy and emergency transfers. In addition, the parallel path flows may cause increased losses in the systems not party to the contracts. Increases in the number of electricity transfers from increased transmission use could exacerbate parallel path flow problems.

- Inadequate Transmission Facilities – Additional transmission lines may not be constructed to keep pace with increasing transmission utilization unless adequate compensation is provided in exchange for use of the transmission systems by those entities receiving transmission service. The inability to reinforce the transmission systems to accommodate increased use will result in degradation of electric system reliability.

Transmission Service Activities

A recent example of emerging transmission service policies is illustrated by the conditions imposed by the Federal Energy Regulatory Commission (FERC) on the Utah Power and Light Company/PacifiCorp merger. The Commission stipulated the following conditions in allowing the merger to proceed:

- The merged company has an obligation to provide firm wholesale transmission service at cost-based rates to any utility that requests such service.

- During a transition period, the merged company is to identify that portion of its total transfer capacity that could be used for firm deliveries by third-party utilities.

- During a transition period, a portion of the merged company's transmission system will be allocated for its own use and for use by third-party utilities.

- The merged company must meet all bona fide requests for service by using existing transmission capacity or by building new transmission facilities. The decision to build new facilities is at the discretion of the merged company.

FERC's initial conditions for the merger outlined transmission service policies for utilities seeking transmission service from the merged company. The merged company believes that it can comply with these conditions while continuing to maintain established reliability standards. Utilities are intimately familiar with the requirements for interconnected system reliability. These requirements must be observed by all participants using the transmission system if the current level of reliability expected and depended upon by the customer is to be maintained.

Another ongoing example intended to establish the value placed on the use of the transmission system is an experiment sanctioned by FERC and being conducted under the auspices of the Western Systems Power Pool. The 24 utility participants can enter into opportunity transactions on the transmission system by paying a price for transmission use based on the perceived value of the transmission system at the time of the transaction. The principle is similar to trading on a stock market with the use of the transmission system being the variable commodity.

Transmission Service Considerations

With the increased interest in transmission service and deregulation, as evidenced by the cited examples, it is important that the following key considerations to maintaining system reliability be incorporated into any transmission service policies:

- Incentives are needed to ensure that future transmission facilities will be constructed to provide sufficient capability to accommodate the anticipated increased levels of use stimulated by increased competition and deregulation. In establishing incentives to build additional transmission lines, it should be recognized that the disadvantages associated with loading the transmission system to or near its capacity, such as reduced stability margins and increased losses, may outweigh the benefits of increased utilization of economy generation.

- All participants utilizing the transmission systems must adhere to electric utility planning and operating policies and practices designed to maintain electric system reliability as described in the NERC Policies, Criteria, and Guides.

- Planning procedures must be established to identify the effects on the transmission network of electricity transfers among buyers and sellers to ensure that adequate transmission capability exists to accommodate such transfers. Parallel path flow problems may increase in magnitude and complexity in proportion to the increasing number of contracted electricity transfers.

- Priorities must be recognized in determining which entities will be able to use the utility-owned transmission systems.

- Operating procedures must be established to ensure that increased transmission service will not reduce the flexibility to accommodate emergency electricity transfers.

- Adequate monitoring, communications, and control systems must be in place to enable system operators to determine if simultaneous system transfer limits have been exceeded. In the event that the limits are exceeded, clear and concise procedures will be required to effect the timely and orderly curtailment of electricity transfers to bring the systems within safe operating levels.

Public policies regarding deregulation and transmission service must recognize the need to maintain adequate system reliability. Resolution of the above issues in a careful and prudent manner is necessary if utilities are to maintain the level of reliability in the future that their customers have come to enjoy and expect.

RELIABILITY ISSUES
Environmental Considerations

Electric utilities recognize the need for environmental protection. While environmental considerations are important, environmental regulations that reduce electric generating capacity, delay new generation and transmission facilities, or reduce the availability of existing facilities pose serious threats to electric system reliability.

Sound technical evaluations of the potential effects of proposed regulations on the environment and on electric system reliability are needed. Stringent environmental requirements may reduce system reliability without achieving significant environmental or health benefits. It is, therefore, important that utilities and policymakers work together to provide a reliable electricity supply in an environmentally acceptable manner.

Environmental Issues

There is concern among the general public, environmental groups, and policymakers regarding the need for increased environmental protection and the impacts of electricity production and delivery on the environment. These concerns relate to both existing and future generation and transmission facilities.

Electric utilities recognize the need for environmental protection and continue to implement measures to minimize the impacts of construction and operation of electrical generation and transmission facilities on the environment. However, environmental concerns raised by individuals, public interest groups, and the public in general, as well as changes to environmental regulations have the potential to adversely impact electric system reliability. These effects include delays in the construction of new facilities and limitations or constraints on the use of existing facilities to meet future customer needs.

Environmental regulations should be carefully developed with sound technical evaluations of their potential costs, benefits, and impacts on the environment and on electric system reliability. Overly stringent environmental requirements may have adverse system reliability effects with no significant environmental or health benefits. Electric utilities should increase their efforts in providing the public and policymakers with easily understood technical information on environmental issues and their impacts on the electric systems, electricity costs, and the environment.

Some of the key environmental issues that are currently impacting or threatening either existing or future generation and transmission facilities are briefly discussed below.

Electromagnetic Fields

Adequacy of electrical supply depends on reliable operation of existing and planned transmission lines. Controversy regarding a possible correlation between electromagnetic fields (EMF) and health effects is widespread, and in some cases, has resulted in the delay or cancellation of planned transmission facilities and the removal from service of existing transmission facilities. Health effect concerns have surfaced in Florida, New York, Ontario, Texas, Arizona, California, Colorado, Maryland, and Washington, and have impacted both existing and planned transmission facilities.

Examples of such concerns include the rerouting of two existing Houston Lighting & Power Company 345 kV transmission circuits, and the cancellation by the city of Austin, Texas, of 345 kV transmission improvements needed to maintain reliability. The Maryland Public Service Commission reopened the certification proceedings on a portion of the long-delayed Baltimore-Washington, D.C. 500 kV loop based on safety and health effects associated with EMF. The Lake Tarpon-Kathleen 500 kV line in Florida, originally planned for service in December 1987, has been indefinitely delayed due to concerns regarding electric and magnetic field effects. These delays are not only causing increased costs due to operation of uneconomic local generation to maintain system reliability in some cases, but are causing reduced electric system reliability due to heavier loadings on existing facilities. Any regulatory action to control electric and magnetic field strengths near transmission lines should include a careful evaluation of potential reliability effects.

In Washington State, two Senate bills were put forward in February 1989. The two bills SB 5274 and SB 5275 were very similar, differing only in the language used to describe the potential effects of EMF associated with electric supply. Bill SB 5274, which incorporated the more urgent language of the two, would have halted all construction of new transmission lines until health effects research could determine safe exposure limits. Bill SB 5274 has died, and bill SB 5275 is being modified to only require an assessment and report on the social and health effects of electric and magnetic fields on the environment and the work force.

The Florida Environmental Regulation Commission adopted emission standards for electric and magnetic fields generated by high voltage transmission lines in January 1989. These new standards for transmission design hold EMF levels on new transmission lines to levels found currently on existing lines. This rule is not expected to adversely affect reliability since these standards are consistent with design practices already used by most utilities. During the setting of these Florida standards, there was no scientific data that conclusively demonstrated adverse health effects, and current transmission design standards are considered acceptable in terms of EMF levels. However, the Florida standards have been challenged in the courts.

Acid Rain

Electric utilities in both the United States and Canada have taken and will continue to take measures to minimize acid gas emissions from power plants burning fossil fuels. These measures include use of lower sulfur fuels, installation of emissions control equipment such as flue gas "scrubbers," and research and development into new clean fuel technologies for generating electricity such as integrated gasification combined cycle generator units and fluidized bed combustion units.

In spite of actions already taken by many utilities to decrease acid gas emissions, the issue of acid rain due to emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x) continues to be a major concern. New U.S. legislation could have an impact on the operation of at least 174,000 MW of existing coal-fired generating capacity installed prior to 1975, the year in which the 1970 Clean Air Act became effective. The Eastern Interconnection would be severely affected since it has 92% of the coal-fired capacity installed prior to 1975. Units installed after 1975 could also be affected.

By 1998, in addition to increased costs, compliance with proposed federal legislation on emissions could cause as much as a 12,600 MW reduction in capacity (or about 4.2% of the total 1998 U.S. coal-fired generating capacity). This capacity reduction would be due to premature retirements and power consumption by the additional emissions control equipment. The impacts in Canada are much less due to the much lower percentage of capacity that is coal-fired (equivalent to 7% of the 1998 total U.S. coal-fired generating capacity).

New nitrogen oxide emissions regulations could be more restrictive than the regulations on sulfur dioxide emissions, even though electric utilities are not the largest nitrogen oxide emitters. Tighter NO_x regulations will not only affect the coal-fired generating units, but they would affect low sulfur oil-fired units and both utility and non-utility gas-fired generators, including combustion turbines.

Many utilities are considering renovation of their aging generating units as an alternative to building new plants. Many of these aging plants in the United States were built prior to 1975 and, therefore, are exempt from portions of the 1970 Clean Air Act. However, emissions restrictions for new plants under this act may be applied to life extensions of aging facilities, making the improvements uneconomic and forcing the retirement of this older capacity. A recent example was the U.S. Environmental Protection Agency's (EPA) ruling in October 1988 on a renovation project at Wisconsin Electric Power Company's (WEPCO) Port Washington plant. The EPA ruled that the Clean Air Act's emissions restrictions for new plants would apply to the renovation work to restore all five 80 MW coal-fired units at the Port Washington plant to operation at full rated output. WEPCO has asked a Federal District court to review the EPA ruling. No resolution is expected until the fall of 1989.

Carbon Dioxide Emissions

There is also a growing concern regarding carbon dioxide emissions and their impact on the gradual warming of the earth's atmosphere – "greenhouse" effect. However, there is considerable scientific debate regarding the links between carbon dioxide emissions from burning fossil fuels, the recent droughts, and the alleged warming of the earth's atmosphere. Further, there is no consensus if immediate action is required and what actions would be appropriate.

Since the burning of all fossil fuels, including the combustion of fuels in the transportation sector, produces carbon dioxide emissions, new regulations and strong public opposition to fossil-fueled electricity generation could have significant impacts on the total NERC generating capacity and the reliability of electricity supply. A total of 495,700 MW of existing fossil capacity (66% of total NERC 1988 capacity) and 39,400 MW of planned fossil capacity (42% of the total NERC additions over 1989-1998) could possibly be affected. These impacts could include unit operating limitations, premature shutdown or retirement of fossil-fired units, and restrictions on the addition of new fossil generating capacity. These restrictions will need to be phased-in and are not expected to come into place until the end of this century or the early 2000s. However, there is utility concern now that very little non-fossil generating capacity is capable of being approved for construction and operation to begin to replace the large amount of existing fossil capacity – the major non-fossil electricity generating source being nuclear power.

In light of the lack of scientific consensus on the greenhouse effect and the severe consequences on electricity supply,

more study is needed before policymakers commit to any far-reaching policies in this area. It could be extremely risky to prematurely enact sweeping environmental policy based on incomplete information.

Regulation and Competing Uses for Hydroelectric Capacity

Regulations requiring hydro reservoir control for environmental and recreational purposes can severely impair operation of the 116,000 MW of existing U.S. and Canadian conventional hydroelectric generating capacity. Pressures to hold constant reservoir elevations and to maintain high dissolved oxygen levels downstream often conflict with the electric utilities' requirement for flexible use of hydro generating facilities depending on hourly supply conditions.

The 1987-88 drought has highlighted the increasing competition over the use of hydro projects and the resulting electrical energy production losses to the utilities. Due largely to continued below normal runoff conditions, the 1988 Pacific Northwest energy delivery to the systems in California was almost 50% below the record delivery in 1985 and 30% below the 1987 delivery. River flows to the main reservoirs, in the predominantly hydroelectric system in the Canadian province of Québec, were 18% below average between January and August 1988. In some of these hydro systems, the projected hydro capacity and energy assume a return to median water conditions within the next two years. In the Pacific Northwest, the May 1, 1989 Columbia River "runoff" forecast is 91% of the most recent 25-year average.

Environmental constraints could also inhibit hydroelectric resource development. For example, although potential undeveloped small hydro resources in the Pacific Northwest are estimated to total 2,000 to 3,000 MW, environmental constraints will probably limit actual development to 400 to 500 MW.

Nuclear Spent Fuel Storage and Disposal

Restrictive regulations or strong public opposition regarding spent nuclear fuel storage and low level radioactive waste disposal could impact the continued operation of 104,600 MW of nuclear capacity (14% of total NERC 1988 capacity) and 14,700 MW of planned nuclear generating capacity (16% of the total NERC additions over 1989-1998). The utilities stringently control the handling and storage of spent nuclear fuel and low level radioactive wastes in accordance with federal and state or provincial regulations. However, this issue continues to be of great concern and interest to the public, and the establishment of a permanent site for spent nuclear fuel storage still requires public hearings and government approval in both the United States and Canada.

Polychlorinated Biphenyls

Polychlorinated biphenyls (PCBs) are a class of synthetic chemicals that were used in the manufacture of a wide variety of products including paints, adhesives, sealants, plastics, rubber, waxes, lubricants, and printing inks. Their main uses in the electrical utility industry were for fire retardant cooling and insulation of smaller transformers and capacitors, and for indoor transformer installations.

In both the United States and Canada, a phaseout and ultimate disposal of all PCB equipment in service, such as older capacitor banks, have been under way since the early 1980s and should be complete within the next five to ten years. The capital expenditures required by electric utilities, as well as the need to acquire and install new equipment could cause some problems, especially if shortages of replacement equipment develop. Outages to allow for equipment replacement will need to be carefully scheduled to avoid degrading the reliability of the electric systems. Utilities and policymakers should continue to work together to provide an appropriate phaseout period to permit an orderly replacement of the many pieces of affected equipment, as well as the removal of PCBs from transformer insulating oil.

RELIABILITY ISSUES

Non-Utility Generation

For some electric utilities, non-utility generators (NUGs) will play a major role in supplying future generating capacity. Of the capacity planned to be installed over the next ten years, 19,100 MW or 20.4% are projected to be NUGs. Because of the large number of NUGs now under contract, utilities are carefully assessing the probability of these units meeting their scheduled service dates or ever coming into service. Other concerns regarding the impact of NUGs on the reliability of the electric systems include their commitment to the purchasing utility, their long-term economic durability, their operation and control, and the adequacy of their fuel supply. Utilities are attempting to address these concerns either through a bidding process or through negotiable contractual arrangements with NUG owners.

Non-utility generation, coordinated with the planning and operations of an electric utility, can be a significant asset to some utilities by supplying capacity that would otherwise be supplied by the construction of additional utility generators.

Types of NUGs

The non-utility generator (NUG) population can be divided into two general categories. First, there are those industrial or other independently-owned units that generate electricity only for their own consumption. The electricity generated by these NUGs reduces the amount of load served by the utility.

The second category includes those NUGs that sell or are projected to sell electrical energy or capacity, or both, to electric utilities. These are the units the utilities are counting on to help serve the needs of their customers. This is the category of NUG units most critical to electric system reliability. Utilities are depending on these units to generate at times of system peak demand, and are therefore including them, along with their own units, as capacity to serve their peak demands. It is only this second category that is discussed in this report and included in the NUG tabulations.

Forecast NUG Capacity

The amount of NUG capacity utilities are including in their capacity plans is increasing. This is shown in Table 9. The impact of NUGs is not uniform across the United States. Nearly 40% of existing and planned NUG capacity is in the states of California, Texas, and New York.

In the WSCC Region, 5,141 MW or about 40% of the planned capacity additions over the 1989-1998 period are projected to be NUGs. With the increasing dependence on NUG capacity, utilities are carefully assessing the amount of this capacity that will actually be available to serve future demands.

Utility Assessment of NUG Viability

Utility experience illustrates that when properly integrated with the electric system NUGs are a viable utility option and can fulfill a utility's need for additional capacity. Many utilities are soliciting bids for future NUG capacity, and most are carefully considering project viability as well as costs in evaluating bids. In these cases, the utility has a chance to review the economics of the NUG proposals, evaluate the construction and operational experience and financial capabilities of the bidders, and develop contracts that will be far more likely to result in economically sound NUG projects coming on line as scheduled. Presumably, only the most promising projects would survive the screening process, and those that do will have the best chance of materializing as expected.

However, this is not always the case. A large number of NUG contracts were negotiated during periods of favorable investment tax credits and when high oil prices resulted in high avoided costs for utilities. Many contracts were mandated based on the then prevalent avoided costs and perceptions of what these might be in the future. The economic viability of many of these facilities is of concern to utilities in view of the present avoided cost outlook and tax structure. Extensive analysis by some utilities estimates that less than half of the NUG capacity under contract is likely to materialize. If this mortality rate were to continue, reliability would be seriously impacted since so much of the added capacity over the next ten years is comprised of NUGs. Utilities need to recognize this likelihood in their capacity planning.

Table 9 — Non-Utility Generator (NUG) Capacity in Recent Forecasts

Region	Summer 1997 NUG Capacity (as % Total Capacity Resources) 1988-1997 Forecast	1989-1998 Forecast	NUG Capacity Additions (Summer – MW) 1988-1997 Forecast	1989-1998 Forecast
ECAR	2.2	2.4	2,139	2,359
ERCOT	4.2	2.5	-31	-1,222
MAAC	5.6	7.1	2,865	3,610
MAIN	<0.1	0.1	12	79
MAPP	0.7	1.1	82	63
NPCC	3.6	4.4	4,232	4,439
SERC	3.6	3.1	4,949	4,107
SPP	0.9	0.8	500	500
WSCC	5.4	6.3	5,381	5,141
NERC-U.S.	**3.8**	**3.9**	**19,844**	**18,115**
NERC-Canada	**0.3**	**1.0**	**285**	**961**

There are several major factors that affect the likelihood that a NUG unit, under contract, will come on line as planned and remain viable over the contract period:

- The developer must be capable of handling the siting, permitting, and environmental problems so that the project can be built as scheduled, or built at all.
- The developer must be able to support the cost of the project, or more importantly, must have the experience, reputation, and creditability to obtain bank or other commercial financing.
- The experience the project owner, engineer contractors, and operators have with similar plants already in operation significantly affects the likely success of new projects.
- The economics of the project must be such that the developer will realize an adequate return on investment, and have sufficient profit margin to withstand increases in fuel costs or adverse business cycles.
- The project must not be dependent upon avoided costs higher than current levels and greater than anticipated in the future.

There are cases in which utilities have bought back contracts from NUG developers. Montana Power Company paid developers to cancel 14 NUG contracts totaling 42.5 MW because the projects were not coming on line as planned, and in some cases, there were no indications they would ever come on line.

The City of Austin, Texas, terminated its contract with Valley View Energy Corporation, which was to construct two 49 MW units fueled by cattle manure to supply electricity for the city. The project had been planned since 1984, but construction had not been started. Austin no longer wanted the electricity from this project because economic conditions had changed and it would have been more expensive than electricity currently available from other sources.

As a safeguard, many contracts now being negotiated by the utilities provide some means for contract termination in the event certain NUG project milestones are not met on schedule.

In addition to the concern about the amount of NUG capacity under contract that will actually come on line, there is also the question of economic durability of those NUGs currently in operation. In the case of cogenerators, the basic industrial or commercial process associated with the NUG must also remain profitable. Otherwise, the NUG owner may be forced to shut down the cogeneration unit even if the electric generation portion of the cogeneration project is still profitable.

As a general rule, utility generating facilities are conservatively designed, carefully constructed, well maintained, and operated within their capabilities to assure a high availability over their intended lives. Comparable prudence by NUG owners should result in essentially the same level of performance. Deferred maintenance, possibly due to marginal profitability or being of second priority to the balance of a cogenerator's plant, may lead to a shortened life span.

Technical problems for some NUGs due to comparatively new technology could also force early retirement. For example, corrosion problems due to burning refuse or biomass, such as manure, or problems with "dirty" steam in geothermal projects could lead to early retirement. Because experience with NUGs is comparatively recent, significant data concerning their long-term, physical durability is not yet available.

Utility Experiences With NUGs

Table 10 shows utility experience throughout NERC with NUGs in 1988. Of the total of 3,952 MW expected to come on line in 1988, 2,941 MW or 74% were actually available for

service at the end of the year. From this, it can be concluded that NUG owners are not immune to problems in getting generation sited, permitted, constructed, tested, and on line as scheduled.

A new NUG bidding process with improved operating criteria is being implemented in the Colorado portion of the Rocky Mountain Power Area. While these qualifying facility tariff provisions are expected to improve dispatchability and availability of NUGs, there is still uncertainty as to the actual amount of NUG capacity that will be installed and its long-term availability.

A noteworthy example of a multi-use NUG facility is a 136 MW plant in Pasadena, Texas, that burns a low quality petroleum coke by-product producing steam for the oil refinery and generating electricity to sell to utilities. Not only does the facility consume an industrial residue, but the limestone from the scrubber is sold for the manufacture of wallboard (sheet rock).

A continuing utility concern with NUGs is that of fuel supply. The availability and recent lower prices for natural gas, combined with relatively short construction periods, and relatively low capital costs, have made combustion turbines the predominant choice for many NUG facilities. A sudden change in the fuel supply environment or additional governmental regulations could drastically limit the ability of many NUGs to obtain fuel. Such a situation may reduce electric system reliability until this NUG capacity can be replaced by the affected utility. For this reason, fuel diversity is becoming an important reliability consideration as gas-fired NUGs become a growing portion of electric utilities' planned capacity additions. Fuel storage capability is also important. However, since many NUGs are baseload units, fuel storage may not be as feasible for NUGs as for utilities, where such units are generally used only for peaking purposes. Future regulations for nitrogen oxides (NO_x) could severely limit combustion turbine capability.

Table 10 — Actual vs. Planned Non-Utility Generator (NUG) Additions (1988)

Region	Planned (MW)	Actual In Service (MW)	Success (%)
ECAR	27	27	100
ERCOT	0	0	–
MAAC	506	221	44
MAIN	0	0	–
MAPP	17	17	100
NPCC	448	316	71
SERC	1,071	685	64
SPP	0	–	–
WSCC	1,883	1,675	89
Total	**3,952**	**2,941**	**74**

Integration of NUGs into the Utility System

Because electric systems were not originally designed for the random integration of NUGs, they may not always be able to accommodate NUG additions without additional transmission. Timely construction of these additional facilities is an important concern to the utilities.

The siting of NUGs can also be a reliability concern. Concentrations of NUGs in areas without sufficient transmission create load-generation imbalances or reduced stability margins, which, if left uncorrected, would adversely impact reliability. If NUGs are located at customer load centers, however, they may actually reduce the utility's transmission requirements.

If the interconnected electric systems are to be operated in as reliable a fashion as in the past, the NUG units coming on line in the future must be capable of functioning as an integral part of the electric network, just as would the utility units that they are replacing.

The reliability requirements for integrating NUGs into the electric systems are addressed in the April 1987 NERC reference document, *Reliability Considerations for Integrating Non-Utility Generating Facilities with the Bulk Electric Systems*. Some of the key planning and operating requirements stressed in this publication include:

- The interconnecting facilities of the NUG must be complete and fully coordinated with the utility facilities.
- The output of NUG units should be controllable and capable of being scheduled. NUG units should also be able to respond to variations in electrical system frequency. Provisions should be made for backup electric supply to cover those instances of scheduled and unscheduled maintenance.
- NUG generators should be capable of being dispatched to match electric utility system demand characteristics.
- The NUG should provide for complete communications, metering, and reporting facilities for coordinating with the utilities.
- Relaying and underfrequency tripping of NUG facilities must be coordinated with the host utility.

- The NUG should provide full and continuous voltage control, power factor control, and reactive power supply capability.

- A firm primary and backup fuel supply with storage should be available and committed for a large portion of the life of the NUG facilities.

With increasing amounts of NUG generation now being secured through the bidding process and by negotiated contracts, many of these aforementioned concerns can be minimized. Under these conditions, non-utility generators are becoming an increasingly attractive capacity strategy for many utilities seeking to avoid building new generating capacity.

REGIONAL ASSESSMENTS

The remainder of this report assesses the electric generation and transmission systems of the nine Regional Reliability Councils. Some key assessment information that is discussed in detail in the front portion of the report for the United States and Canada is summarized in the following table and four figures for the Regions. These include a summary of 1998 projections (below), annual growth rates for peak demand and annual net energy for load, generating unit additions by fuel, generating capacity by fuel, and electrical energy production by fuel.

Detailed regional reliability assessments are described in the following nine chapters.

Summary of 1998 Projections for the Regional Reliability Councils

Regions	Summer Peak Demand (Thousands of MW)	Annual Net Energy for Load (Millions of MWh)	Summer Generating Capability (Thousands of MW)	Summer Capacity Margin[a] (% Planned Capacity Resources)	Transmission Systems[b] (Circuit Miles in Thousands)
ECAR	87.7	495	106	17.3	16.1
ERCOT	50.1	252	59	16.8	7.9
MAAC	47.4	259	58	18.7	7.2
MAIN	44.2	223	49	14.7	5.7
MAPP	32.9	181	41	25.0	20.6
NPCC[c]	104.3	670	133	28.5	36.5
SERC	145.4	765	166	15.2	29.7
SPP	59.3	285	69	14.9	12.0
WSCC[d]	120.3	744	155	23.3	70.4
NERC-Total	**692**	**3,874**	**836**	**19.8**	**206**
NERC-U.S.	**623**	**3,349**	**733**	**17.6**	**158**
NERC-Canada[c]	**67.5**	**517**	**101**	**36.2**	**47.4**

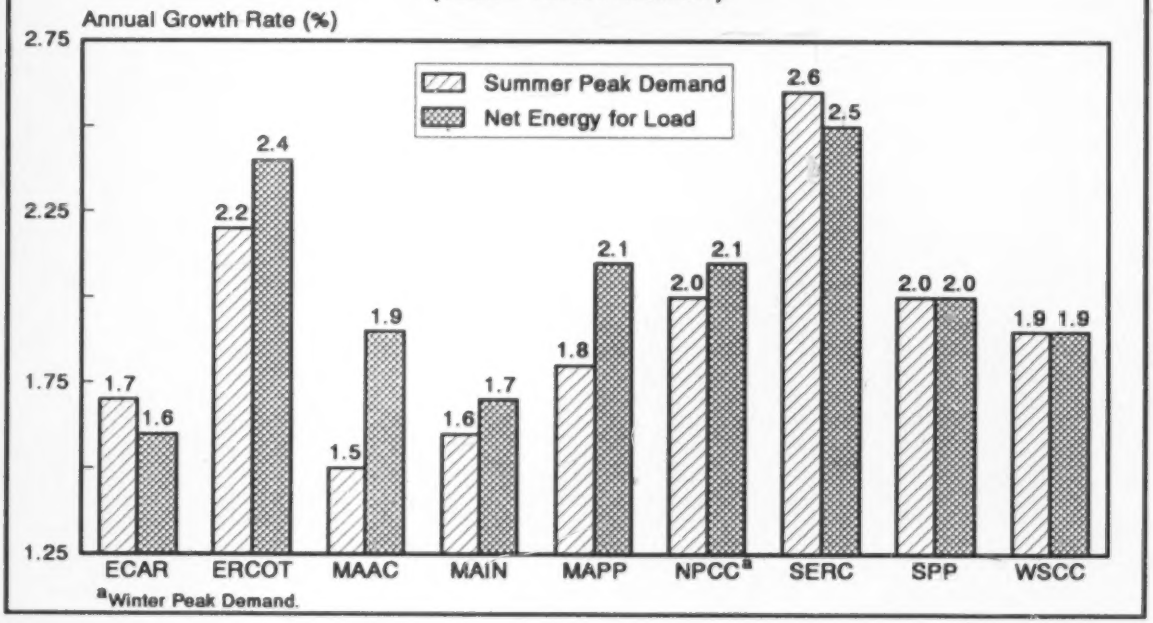
[a] Capacity margin in percent is calculated by dividing the difference between planned capacity resources (Item 3A, line 13, IE-411 reports) and net internal demand (Item 3A, line 06, IE-411 reports) by planned capacity resources and multiplying by 100. Capacity margins cannot be calculated using the peak demands and generating capabilities shown in this table.

[b] Includes ac and dc existing and planned transmission lines operating at 230 kV and above as of December 31, 1998.

[c] NPCC and NERC-Canada are winter peaking with 1998/99 winter peak demands of 119,611 MW and 91,130 MW, respectively. The 1998/99 winter generating capabilities are projected to be 138,113 MW for NPCC and 104,400 MW for NERC-Canada. The 1988/89 winter capacity margins are 19.3% for NPCC and 16.3% for NERC-Canada.

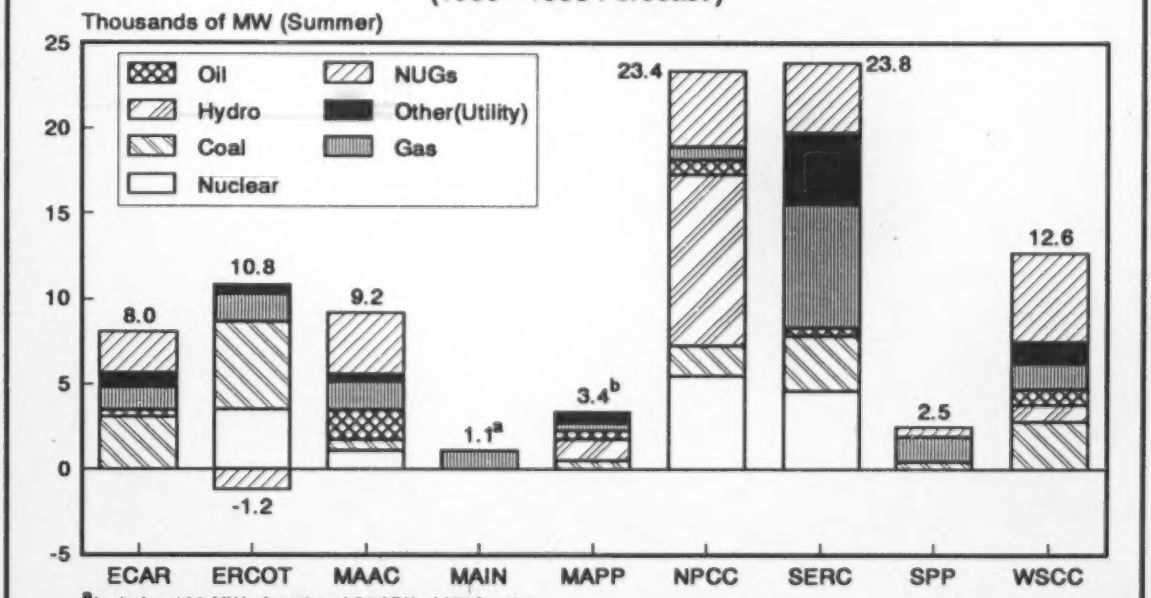
[d] Includes that part of the Comision Federal de Electricidad system in the northern portion of Baja California, Mexico, which is interconnected with the U.S. systems.

Regional Annual Growth Rates for Peak Demand and Annual Net Energy for Load
(1989 – 1998 Forecast)



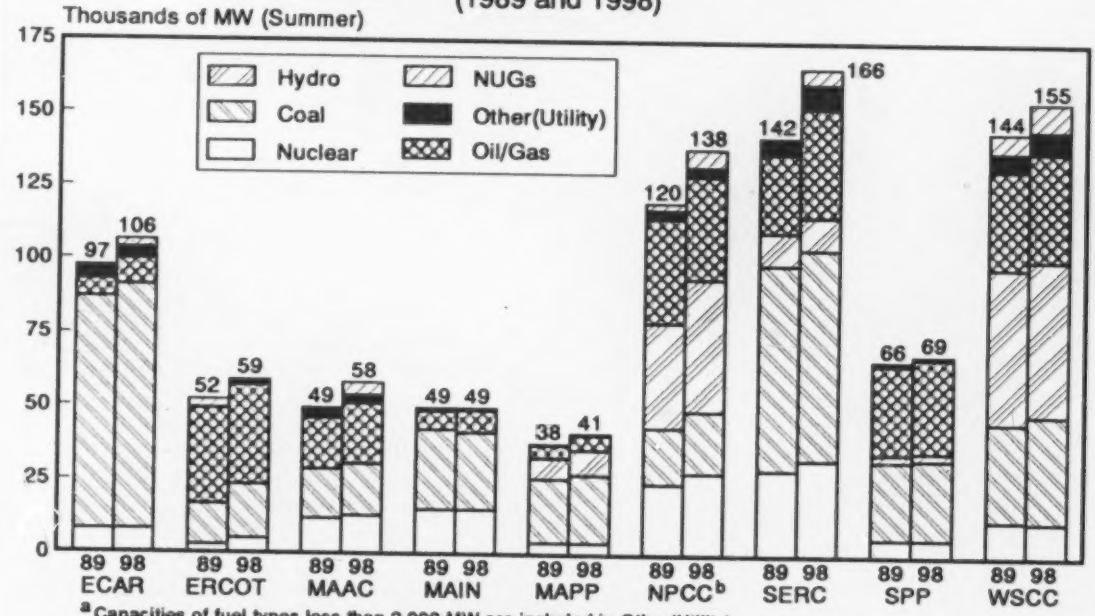
[a]Winter Peak Demand.

Regional Generating Unit Additions by Fuel
(1989 – 1998 Forecast)



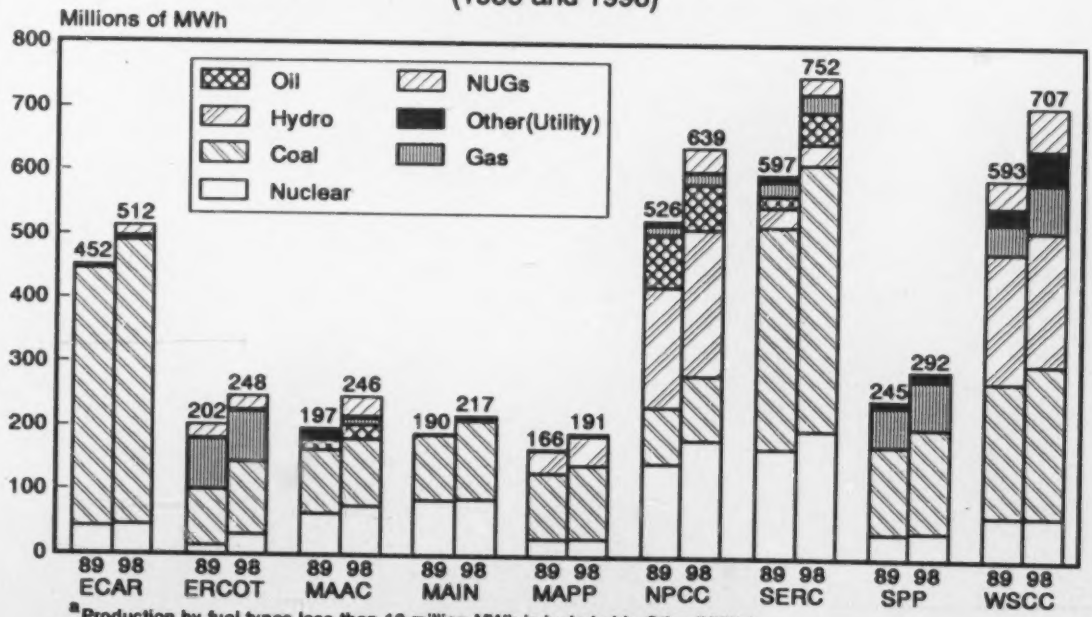
[a]Includes 129 MW of coal and 79 MW of NUG units.
[b]Other(Utility) includes 63 MW of NUG units.

Regional Generating Capacity by Fuel[a]
(1989 and 1998)



[a] Capacities of fuel types less than 2,000 MW are included in Other(Utility).
[b] Winter generating capacity for 1989/90 and 1998/99.

Regional Electrical Energy Production by Fuel[a]
(1989 and 1998)



[a] Production by fuel types less than 10 million MWh is included in Other(Utility).

ECAR

EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

The electric capacity resources planned in the ECAR Region will satisfy the ECAR criterion for adequate reliability provided that availability of generating equipment continues at present levels, and demand and capacity conditions are as projected. However, a small decline in the availability of generating equipment, a slight increase in the rate of demand growth, or other factors, such as implementation of mandated acid rain control strategies, could quickly reduce the future electric system reliability to unacceptable levels.

The transmission network in ECAR is judged to be adequate to handle a wide range of contingencies. This judgment is based on analysis and review of transmission appraisals within ECAR and between ECAR and neighboring Regions. However, portions of the transmission network in eastern ECAR are expected to be heavily loaded much of the time for the foreseeable future. Operating procedures have been established to ensure that electricity transfer schedules are limited to levels that will make it possible to safely withstand any single generation or transmission contingency that might occur.

ECAR	Actual Summer	Actual 1988	Forecast 1989	Forecast 1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		79,149	75,589	87,694	1.7
Winter Peak – MW		68,977	72,412	84,483	1.7
Annual Energy – GWh		429,198	430,377	494,737	1.6
Installed Capability (Summer) – MW		97,121	97,356	106,086	1.0

Peak Demand and Energy

The aggregate of the peak demand projections by systems in ECAR shows that the Region is expected to be summer peaking throughout the 1989-1998 period. The average annual growth in projected peak demand for 1989-1998 is approximately 1.7% for both summer and winter. Last year it was 1.6% for summer and 1.7% for winter. A comparison of the projected peak demands for the common years 1989 through 1997, however, shows that the current summer peak demand projections are 3 to 4% higher this year than last, and the current winter peak demand projections are approximately 2% higher. This is a reflection of the higher-than-expected peak demand levels that were experienced during each of the past three years. The following figure shows a comparison of recent forecasts and actual peak demands.

The projected annual net energy for load in ECAR shows an equivalent compound growth rate of about 1.6% per year over the forecast period. The projections for the common years are 2 to 3% higher in this year's forecast than in last year's.

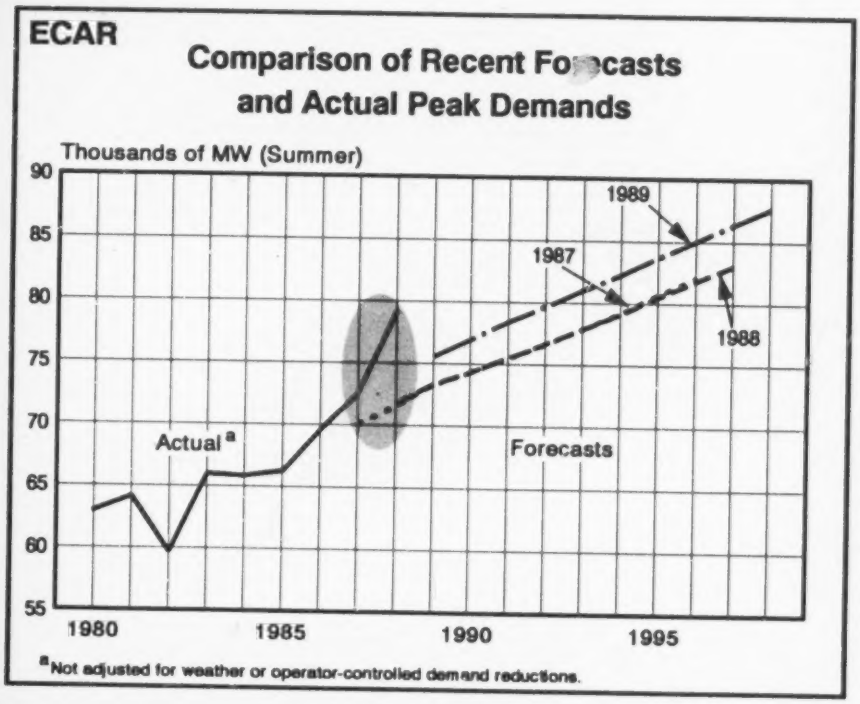
Coal-fired generating capacity will supply about 90% of the electrical energy produced in ECAR over the forecast period and nuclear will supply about 9%. The availability of materials and services for the nuclear fuel cycle (uranium conversion, enrichment, and fabrication) will continue to be adequate to meet requirements in ECAR for the foreseeable future. However, issues involving spent fuel storage and disposal must still be resolved.

Capacity Resources Adequacy

The only major generating unit additions during the forecast period are three coal-fired units – Rockport 2, Zimmer 1, and Trimble County 1 – totaling 3,095 MW. All three units are scheduled for service by the summer of 1991.

Non-utility generators (NUGs) are projected to increase from 219 MW at the beginning of 1989 to 1,683 MW by the 1991 summer season. This increase includes the 1,240 MW Midland Cogeneration Venture Project scheduled for service during 1990.

ECAR



The generating unit additions projected after the summer of 1991 include 1,882 MW of combustion turbines, 840 MW of an unknown type, and 888 MW of non-utility generation projects. However, there is uncertainty associated with any construction schedule and one or more of the NUG projects may be delayed because of construction difficulties, licensing problems, or other reasons. The lead time required for capacity additions such as large fossil-fired units would make it very difficult to react to higher than projected demand growth or an unexpected loss of generation capability (e.g., impact of potential acid rain legislation) in a timely manner.

Extensive appraisals of the adequacy of projected generating capacity margins have been conducted within ECAR using probabilistic techniques and procedures. The appraisals are based on consideration of the regional pattern of daily peak demands for each month of the study period, the status of scheduled generating unit additions, and the expected availability of generating equipment.

The availability of generating equipment is the most critical parameter and high availability continues to be a goal of ECAR members. However, it may be increasingly difficult to maintain generating unit availability at the favorable high levels experienced in recent years since capacity margins will decrease as demand grows, placing greater demands on generating units. This may make it impossible to properly coordinate an adequate planned maintenance program. Environmental restrictions and any mandated additions of emissions control equipment could further degrade the availability of generating equipment. The 1989 ECAR appraisal shows that if the demand and capacity are as projected, the ECAR criterion for judging the adequacy of the projected resources will be satisfied throughout the 1989-1998 period provided that the annual availability of generating equipment continues to exceed 76%.

Transmission System Adequacy

The electric utility systems in ECAR have developed an extensive and reliable high voltage and extra high voltage (EHV) transmission network that is interconnected with the networks in neighboring Regions at various voltage levels. The EHV portion of the network in ECAR consists of over 2,000 miles of 765 kV, over 800 miles of 500 kV, and over 11,700 miles of 345 kV transmission. Current plans call for the addition of approximately 100 miles of 500 kV and 100 miles of 345 kV transmission during the 1989-1998 period. These planned additions will enhance the bulk transmission network that exists today.

In recent years, fuel cost differentials have created numerous opportunities for large scale economy transfers in addition to the long duration transfers. Significant amounts of energy transfers have been arranged on a daily and an hourly basis. These intraregional and interregional transfers have become routine and will continue to be an important consideration in the operation of the interconnected transmission systems for the foreseeable future. These multi-party electricity transfers have caused transmission loading patterns that were not anticipated at the time the transmission systems were originally planned.

Intraregional transmission system performance studies are conducted by ECAR to assure that the member systems meet regional reliability criteria. In addition, ECAR participates with neighboring Regions in system performance studies as part of the activities related to the MAAC-ECAR-NPCC, VACAR-ECAR-MAAC, and MAIN-ECAR-TVA interregional coordination agreements. These agreements provide for exchange of information related to bulk electric supply reliability and for review and analysis of such information.

The East Central Area Reliability Coordination Agreement (ECAR) Region bulk power membership currently consists of 27 companies (18 systems) which serve either all or part of the states of Michigan, Indiana, Kentucky, Ohio, West Virginia, Virginia, Pennsylvania, Maryland, and Tennessee.

Transmission performance studies are conducted prior to each summer and winter season and, on a regular basis, for future periods of interest. An assessment of the expected voltage performance has become an integral part of these studies. The purpose is to provide assurance that the planning and operation of the interconnected systems are properly coordinated. In general, these studies indicate that the ECAR bulk transmission systems should perform adequately under a wide range of credible system conditions. However, portions of the transmission systems in eastern ECAR, which have been heavily loaded much of the time during recent years due to large interregional transfers, are expected to remain heavily loaded for the foreseeable future.

In 1988, Allegheny Power System, the Pennsylvania-New Jersey-Maryland Interconnection, and Virginia Power, with participation by other affected systems, developed multi-level operating criteria identified as the Reliability Coordination Plan. This plan was developed to ensure that transfer schedules are limited to levels that will make it possible for the systems to safely withstand any single contingency.

Impact of Proposed Acid Rain Legislation

During recent years, a number of acid rain bills have been introduced in the U.S. Congress. Since coal is the predominant fuel (90% of total electrical energy requirements) used within the ECAR Region, the reliability impact of compliance with acid rain legislation could be very severe on individual ECAR member systems and their customers.

To assess the impact that such legislation could have on the reliability and adequacy of bulk electric supply in the ECAR Region, two study scenarios were developed. These scenarios encompassed the ranges for emissions limits for fossil-fired units that appeared in 1988 legislative proposals. Each system in ECAR was requested to identify a possible control strategy for achieving these emissions limits and to provide an estimate of reliability impacts, i.e., any change in rating and/or availability of generating equipment on a unit-by-unit basis.

These scenarios indicated a very adverse effect on the adequacy of ECAR generating capacity. To achieve the targeted average annual emissions levels and still maintain a reliability level equivalent to that provided by current capacity plans, at least 9,000 MW of additional new generating capacity would be required. This new capacity would be needed to offset the anticipated poorer availability of some of the generating units retrofitted with emissions controls; and to replace approximately 7,300 MW of capacity lost because of premature retirement, additional auxiliary electrical requirements, and other deratings associated with necessary plant modifications.

ERCOT

ELECTRIC RELIABILITY COUNCIL OF TEXAS

Based on current capacity and demand forecasts, generating capacity margins for the Region are adequate and will vary from 23.6% to 16.8% over the forecast period. Transmission system inadequacies continue to be a major concern in providing for future reliability and economy energy transfers. Peak demand and annual energy forecasts continue to indicate a reduced rate of growth.

ERCOT	Actual Summer	Actual 1988	Forecast 1989	Forecast 1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		40,843	41,169	50,085	2.2
Winter Peak – MW		34,628	33,092	42,264	2.8
Annual Energy – GWh		201,472	202,683	251,636	2.4
Installed Capability (Summer) – MW		49,227	52,121	58,759	1.3

Peak Demand and Energy

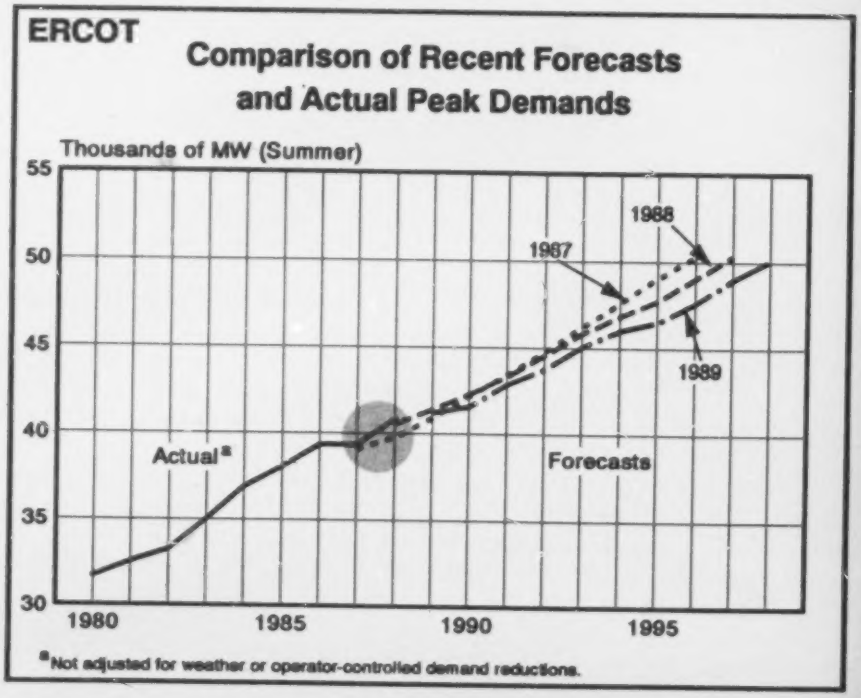
The 1988 actual summer peak demand in ERCOT exceeded the forecast by 0.8%, primarily due to the high temperatures during the drought conditions experienced that year. Actual summer peaks have slightly exceeded their one-year forecasts for three of the last five years.

The summer peak demand forecast by ERCOT member utilities indicates an average annual growth rate of 2.2% for the 1989-1998 period, a reduction from the 2.4% rate projected last year. The projected 1997 summer peak is down 1,404 MW from last year's forecast.

Utility-controlled load management programs, including interruptible demands, range from 972 MW or 9.8% of the projected summer capacity margin in 1995 to 1,461 MW or 13.7% of the projected capacity margin in 1994. Annual energy growth for the 1989-1998 period is currently estimated at 2.4%, compared to 2.9% for the 1988-1997 period. Slow economic growth continues to be the primary cause of the lower peak demand and energy growth rates.

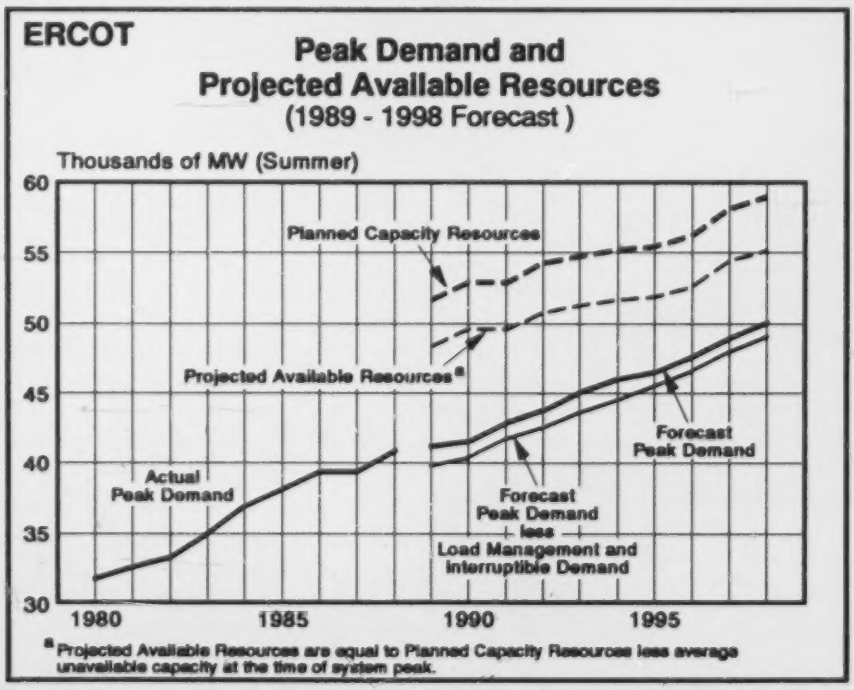
Capacity Resources Adequacy

The capacity margin within the Region is expected to range from a high of 23.6% in 1990 to a low of 16.8% in 1998. Capacity purchases, principally from non-utility generators, are being used to supplement ERCOT capacity on both a



short- and long-term basis. Projected capacity margins are greater than the planning guidelines adopted by the Region, thus planned capacity resources are expected to be adequate during the 1989-1998 period. Currently projected capacity resources could support an annual summer peak demand growth of 2.8%, compared with 2.2% currently forecasted, without violating ERCOT Planning Criteria. A comparison of ERCOT's projected available resources and peak demands over the forecast period is shown in the following figure.

During 1988, utility-owned generating capacity increased by 2,646 MW. New utility-owned generating capacity scheduled for installation between 1989 and 1998 totals 10,854 MW. This includes 5,136 MW of coal-fired capacity, 37 MW of utility-owned refuse burning capacity, 662 MW of combustion turbines, 969 MW of combined cycle generation, 3,550 MW of nuclear capacity, and 500 MW of unspecified resources. Net reratings of existing units are expected to add 263 MW, and units moving into and out of deactivated status will add a net 276 MW. Retirements during the period are expected to remove 1,236 MW, and non-utility generating capacity is projected to decline by 1,222 MW based on the expiration dates of several firm capacity contracts. The total net increase in capacity is 8,935 MW. Non-utility generators, mainly cogeneration, are forecast to account for 2,952 MW or 5.7% of 1989 summer capacity resources and 1,324 MW or 2.2% of the 1998 summer capacity resources. Without the expected capacity contributions of non-utility generators, the Region's 1998 summer capacity margin would decrease from 16.8% to 14.9%.



The first of the Region's four nuclear units, South Texas One, went into commercial operation in August 1988. The second South Texas unit went into commercial operation in June 1989, and the two Comanche Peak units are scheduled for service after the summer peak demand seasons of 1989 and 1991.

ERCOT is improving its fuel mix, but will remain heavily dependent on natural gas throughout the forecast period. Gas-fueled electrical energy production by utilities will amount to 39.2% of ERCOT's total annual energy requirements in 1989 and will drop to 31.8% in 1998. Electrical energy production by non-utility generators adds approximately nine percentage points to the total percentage of gas-fueled energy resulting in a 40.4% gas-fueled energy projection for 1998.

Transmission Adequacy

ERCOT members expect to install approximately 1,075 circuit miles of 345 kV transmission lines during the next ten years. This represents a 15% increase from the ten-year projections made in 1988 and an 18% reduction from the ten-year projections made in 1987.

A proposed East DC Tie to be jointly-owned by utilities in ERCOT and the Southwest Power Pool will have a capacity of 600 MW directly linking Texas Utilities Electric Company with Southwestern Electric Power Company. The East DC Tie has received Federal Energy Regulatory Commission approval and is scheduled for completion by the summer peak of 1992.

The proposed Salem-Zenith interconnection, a 345 kV double circuit line between Houston Lighting & Power Company (HL&P) and the Lower Colorado River Authority (LCRA), is still awaiting Texas Public Utility Commission (PUC) action. After the 1985 PUC decision denying permission for construction of the line, a State District Court remanded the application to the PUC for reconsideration. An appellate court confirmed the District Court remand, but the case has now been appealed to the State Supreme Court.

Another transmission project that will not be in service as originally scheduled is a 345 kV transmission tie interconnecting HL&P, LCRA, and TU Electric. This line is associated with the aforementioned HL&P-LCRA inter-

ERCOT

connection and will likely be delayed until the HL&P-LCRA interconnection is approved.

As described in last year's assessment, Austin will not meet ERCOT Planning Criteria during portions of 1989. A short range plan that will significantly improve Austin's reliability was approved in March 1988 and is presently being implemented. A long range transmission plan that will allow Austin to meet the Criteria was approved in concept by the City Council.

Operations

Various forms of interutility and non-utility generation wheeling have contributed greatly to the economic operation of the ERCOT systems. During 1988, a total of 16,423 GWh of interutility energy transfers occurred, with 10,340 GWh of this total representing energy generated by non-utility generators. Economy energy transferred through the use of the ERCOT Bulletin Board and Broker Systems increased by 12.7% from 1987 to 1988. These transfers continue to benefit ERCOT customers through the use of available transmission capacity to reduce electricity production costs. Texas PUC rules and ERCOT guidelines, which facilitate utility and qualifying facility access to the ERCOT transmission network along with wheeling compensation for all affected systems, have further stimulated the use of the ERCOT transmission network.

During September 1988, Hurricane Gilbert threatened the Texas Gulf Coast. In response, non-utility generators in the area began notifying the ERCOT utilities that they might declare *force majeure* and leave the system. The ERCOT utilities responded to the non-utility generators' notifications and made preparations to ensure that their own generation would remain adequate.

Reliability Issues

The key reliability issues of concern to the ERCOT member systems are:

- Transmission Wheeling – Wheeling of purchased electricity is a growing concern in ERCOT. Purchases from sources other than the utility control area to which a wholesale customer is connected places an increased burden on host utilities to control these transactions. While not a current threat to reliability in the Region, these types of wheeling transactions could become a major threat to the utilities' ability to control the loadings on the bulk transmission systems in the future.
- Construction of Additional Transmission Facilities – The increased use of the ERCOT transmission systems for both firm and economy energy interchanges has placed a significant strain on certain portions of the existing network. Of particular concern is the fact that the transmission systems in place today are not the systems that were planned, due to impediments delaying the construction of a number of planned facilities.

  The 345 kV Salem-Zenith interconnection between HL&P and LCRA, which was rejected by the Texas PUC in November 1985, and the cancellation of 345 kV construction in the Austin area are situations which have served to weaken the ERCOT transmission network. Further increases in the use of the transmission network for either reliability or economic reasons will require the cooperation of utilities and regulators in overcoming impediments to the construction of critically needed interconnection facilities.
- Natural Gas Supply – ERCOT utilities depend heavily on natural gas. Approximately 40.4% of ERCOT's annual electrical energy requirements in 1998 will be fueled by natural gas. The long-term availability of natural gas is therefore a major concern. While ERCOT utilities are currently benefiting from abundant supplies and attractive prices for natural gas, the relatively low gas prices have resulted in reduced drilling activities and deterioration of gas reserves. Despite having vigorously pursued fuel diversification, ERCOT utilities will, through the integration of non-utility generators into their resources, continue to be heavily dependent on natural gas. Non-utility generators, whose principal fuel is natural gas, serve to displace construction of utility-owned capacity which would use other fuels. While experts disagree on when it will occur, most agree that sometime in the future the current abundant supply of natural gas will be diminished and shortages will occur until exploration is increased and additional gas reserves are discovered. Tightening of gas supplies and somewhat higher prices have recently been experienced during the peak winter months in ERCOT. This trend is expected to continue in future years.
- Alleged Health Effects of Electromagnetic Fields – There is growing concern among ERCOT utilities that the public perception of EMF health effects may have a significant impact on the construction and continued operation of transmission facilities within ERCOT. Concerns voiced at public hearings in Austin and a condemnation case involving HL&P and the Klein Independent School District have brought this issue into sharp focus. The Texas PUC has initiated the appointment of a special committee to advise it regarding EMF research. There is considerable uncertainty at this time as to the full impact of this issue, which will be watched closely by ERCOT member utilities.

The Electric Reliability Council of Texas (ERCOT) is comprised of 25 municipalities, 51 cooperatives, six investor-owned utilities, and two state agencies which serve a total of 11 million customers. These systems operate 85% of the electric generation in Texas and serve approximately 195,000 square miles – 73% of the area in the state.

MAAC

MID-ATLANTIC AREA COUNCIL

Projections of MAAC's annual peak demand for the next ten years have increased since last year's forecast. Capacity plans have been increased as a result of these expected higher peak demands; however, even more capacity additions are required in some years to provide capacity margins needed to meet MAAC's reliability objective. Tight operating conditions can be expected over the forecast period. Steps to improve availability of existing capacity and capacity purchases are being pursued.

The ability of the transmission network to deliver emergency assistance from neighboring Regions is a concern in MAAC based on recent experience when transmission limitations in other systems have restricted emergency assistance. MAAC is undertaking both internal and joint studies to better define future transmission system needs.

Another concern is the potential impact of higher than forecast peak demand. There could be significant shortfalls in planned capacity if peak demand continues to grow faster than projected. If this occurs, large amounts of additional capacity resources would be required in a short time period.

MAAC	Actual Summer	Actual 1988	Forecast 1989	Forecast 1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		43,110	41,565	47,365	1.5
Winter Peak – MW		36,363	36,980	44,691	2.1
Annual Energy – GWh		218,636	218,772	259,306	1.9
Installed Capability (Summer) – MW		48,669	49,208	57,754	1.8

Peak Demand and Energy

The summer of 1988 marked the sixth consecutive year MAAC experienced an all-time record peak demand. The actual 1988 summer peak of 43,110 MW with voltage reductions and load curtailments in effect exceeded the forecast by more than 3,500 MW, or 8.9%. The amount of customer demand not served at the time of peak due to load management and emergency procedures was over 1,500 MW. Actual peak demand exceeded the forecast on 16 days during the 1988 summer period. The 1988 peak exceeded the peak demand that was forecasted for 1994.

Net annual energy for the MAAC system in 1988 was 5.2% above forecast. The growth in energy is projected to be 1.9% per year over the next ten years.

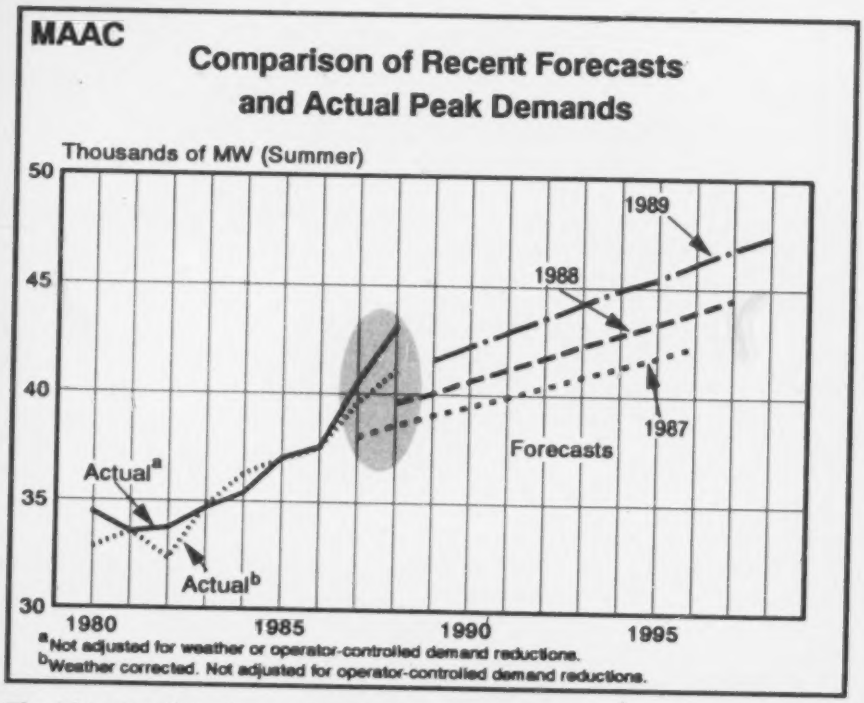
Adjustments have been made to MAAC forecasts to reflect recent experience. The current peak demand forecast for 1989 summer is 1,500 MW greater than last year's forecast. The annual growth rate is projected to be 1.5% per year as compared to 1.3% last year. The higher starting point and greater annual growth rate result in an increase of 2,300 MW in 1997 peak demand as compared to last year's forecast. Peak demand history and a comparison of recent forecasts are shown in the following figure.

The summer peak demand projections include the effects of demand management programs. By 1998, the effect of the load management portion of these programs is projected to have reduced peak demand by 2,600 MW.

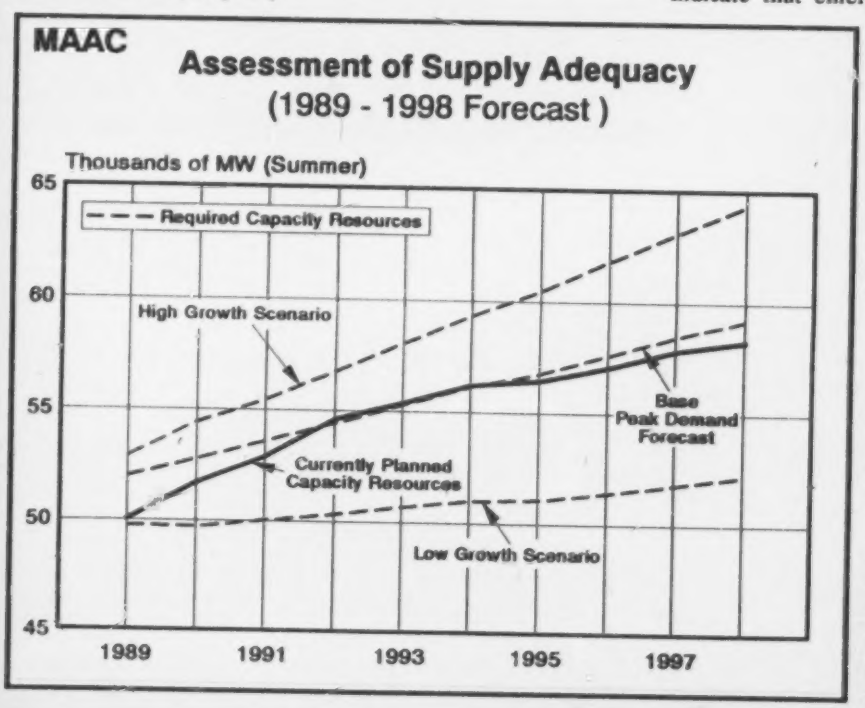
Capacity Resources Adequacy

The capacity resources in MAAC are expected to increase by a net 8,200 MW between 1989 and 1998. The breakdown of new resources to be added is: baseload utility generators – 19%; short lead-time utility generators – 42%; and non-utility generators – 39%. Offsetting these new source additions are retirements and reduced purchases from other Regions.

MAAC



The MAAC utilities have adjusted their capacity plans to provide for the increase in forecast peak demand. The net increase in planned generating resources is 2,000 MW more this year for 1997 than reported last year. About half of this adjustment is short lead-time utility capacity and the other half is non-utility capacity.



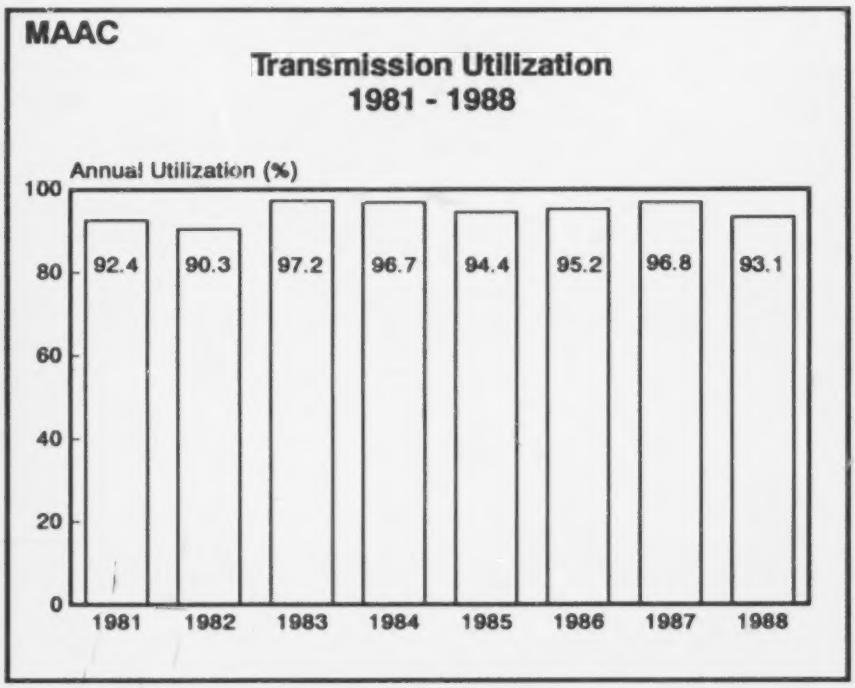
A comparison of planned capacity resources and capacity resources required for the peak demand projections is illustrated in the figure below. It can be expected that MAAC will have tight operating conditions throughout this period. To minimize the impact on reliability, MAAC utilities are taking steps to increase availability of existing facilities. Also, some companies are pursuing arrangements for purchases from other Regions.

Transmission Adequacy

The MAAC companies plan to add 498 miles of 230 kV and 123 miles of 500 kV transmission lines by 1998. A portion of these additions is the completion of the Baltimore-Washington 500 kV loop. This loop is required to provide adequate interregional transfer capability near MAAC's western interfaces and adequate stability margins in the Baltimore-Washington area. However, this line continues to be delayed by the approval process and seemingly endless court action.

Planning studies conducted by the MAAC companies indicate that emergency import capability of the planned system will be adequate to import the amount of emergency assistance expected to be available from nearby Regions. Important assumptions for these studies are that transmission is constructed as planned, no unexpected transmission limits occur in neighboring systems, and attempted simultaneous use of the interregional transmission network by MAAC and others doesn't compromise the ability of MAAC to receive emergency assistance from neighboring systems. Changes in these assumptions can significantly change the results of the planning studies. The assumptions and their effects on MAAC are continually being evaluated.

One such evaluation was to analyze the conditions that existed during the 1988 summer. It was found that limits on transmission systems external to MAAC restricted the assistance MAAC was able to receive under some circum-



stances. On the days when peak demand conditions existed in MAAC, the actual import capability was lower than predicted by transmission planning studies. This difference between projections and actual experience has raised concern about the future adequacy of MAAC's emergency import capability. MAAC is currently reassessing emergency import capability and the study assumptions that affect this analysis in an attempt to better define transmission needs. Joint studies involving MAAC and neighboring systems in ECAR and SERC are in progress to evaluate alternatives, including series and shunt capacitor installations, to improve interregional and intraregional transfer capability.

Emergency import capability is of no help to MAAC unless there is generation available in other Regions at MAAC's time of need. The projected decline of capacity margins throughout the Eastern Interconnection is of concern, especially during conditions such as occurred in 1987 when peak demand diversity between Regions diminished, leaving operating capacity margins perilously low. This concern is also a factor in determining future transmission needs.

Operations

The MAAC transmission network continues to be operated close to its full capability. Utilization, as shown in the above figure, has been greater than 90% since this measure for transmission utilization was developed for use in MAAC in 1981. The heavy loading on the MAAC transmission network is the result of internal MAAC economy interchange, economy imports from systems west of MAAC, and unscheduled flows resulting from transactions among neighboring systems. Some of the factors that can influence transmission system loading in the future are the continued availability of economy energy from western systems, the amount and location of non-utility and utility generation additions within MAAC, and transmission system reinforcements. Although these factors can affect transmission system loading either way, it is expected that use of the transmission network will continue at high levels through the next ten years.

Along with heavy transmission loadings, the operation of the system will continue to be complex. Voltage limits that are more difficult to determine and monitor than thermal limits will be common; the impact of unscheduled flows and the addition of control devices will require greater coordination and information exchange; heavily loaded systems will require close monitoring and precise control; and scheduling facilities for maintenance will be difficult. MAAC continues to work closely with neighboring Regions to coordinate operations. The Reliability Coordination Plan jointly implemented among systems in MAAC, ECAR, and SERC in 1988 is an example of these cooperative efforts. MAAC also is working toward improving its operating analysis and monitoring tools so the system can be operated close to limits while still maintaining reliability.

Reliability Issues

Several factors that can adversely affect the adequacy of future supply capability in MAAC include:

- Higher Than Forecast Demand – Planned capacity, which is marginally adequate over the forecast period, will have to be increased if demand grows faster than current projections. For example, by the end of the ten-year period, more than 6,000 MW of additional capacity would be required if demand grows at 2.2% per year instead of the 1.5% forecasted. This would be a significant change to current capacity expansion plans and would have to be implemented within a short period.

The options for capacity additions in this short lead-time situation are limited under the best of circumstances.

MAAC

However, success of a short lead-time capacity addition strategy is dependent on three major factors. These are: (1) the ability to manufacture the required capacity in a timely manner, (2) the ability to site the required capacity in a timely manner, and (3) availability of uncertain supplies of oil and gas. Delays or unavailability caused by any of these or other factors could lead to inadequate capacity margins.

On the other hand, capacity resources would be adequate throughout the planning period if peak demand grows at a slower rate (0.5%/year or less) than the base forecast rate.

- Emergency Import Capability – The transmission systems in and around MAAC continue to be heavily loaded for various types of economy and emergency transactions. The cumulative effect of the large number of simultaneous transactions causes loadings on facilities that are critical to interregional transfers to approach safe operating limits. Reliability is reduced if all needs for transmission capability cannot be satisfied simultaneously.

  It has been difficult to provide transmission reinforcements needed to meet growing system needs. For example, the Baltimore-Washington 500 kV loop continues to face delays even though it is an important transmission link that improves transfer capability among the MAAC, ECAR, and SERC Regions and impacts the reliability of supply to the Washington, D.C. area.

  Major new transmission projects that could improve interregional system performance are difficult to justify for individual utilities, yet the divergent interests and needs of various utilities discourage joint efforts, as does the uncertainty of regulatory approvals. Also, generally declining capacity margins throughout the Eastern Interconnection raise the question about how much emergency help may be available even if transmission capability were increased.

- Continued Availability of Existing Generation – Because the demand/supply balance in MAAC is so delicate, MAAC cannot lose any existing capacity without risking supply inadequacy. Environmental-related legislation that affects coal-fired capacity and unit availability, extended nuclear unit shutdowns, or disruption of gas and oil supplies are three factors that could reduce the continued availability of existing generators. Even relatively small reductions would increase exposure to supply deficiencies.

The MAAC Region consists of 11 member systems and five associates serving over 20 million people in a 48,700 square mile area. The Region includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey, and Maryland, and a small portion of Virginia.

MAIN

MID-AMERICA INTERCONNECTED NETWORK

Analyses show that generating capacity in MAIN may be less than required for adequate reliability in the mid to late 1990s. Additional demand management programs or short lead-time capacity will be needed to assure reliability, but plans have not yet been finalized.

A major reliability concern is the unknown effects on future generating capability of regulatory actions related to acid rain. Additional concerns are supply adequacy should peak demand exceed projections, and possible adverse reliability impact due to extended lead times resulting from manufacturers' inability to meet future utility requirements for electrical equipment, especially combustion turbines.

The transmission network in MAIN is adequate for reliable operations for both internal transfers and those involving adjoining Regions.

MAIN	Actual		Forecast		
	Summer	1988	1989	1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		41,139	38,415	44,181	1.6
Winter Peak – MW		30,631	30,835	36,331	1.8
Annual Energy – GWh		194,101	190,644	222,720	1.7
Installed Capability (Summer) – MW		49,336	49,401	49,426	0.0

Peak Demand and Energy

The 1988 peak demand for MAIN was higher than expected. The actual summer peak demand of 41,139 MW was a new all-time high, and it exceeded the demand that was forecast for 1994. This new summer demand was 9.8% above that for 1987 and 10.3% above forecast. The 1987 demand was 4.2% above the 1986 peak. During July and August of 1988, temperatures were above normal for extended periods over most of the MAIN area.

The MAIN 1988 summer peak demand was reduced about 196 MW by removal of contractually interruptible customer demand. Also, one member utility reduced its peak by 69 MW through a 2.5% voltage reduction on certain distribution circuits.

Actual peaks and a comparison of recent peak demand projections are shown in the following figure. Summer peak demand for the 1989-1998 period is forecast to increase at an average annual rate of 1.6%, slightly above the 1.5% rate forecast last year. The current forecast shows significant change from last year's forecast for specific future years. For example, the present forecast for 1997 summer peak is 840 MW or 2% higher than that made last year for 1997.

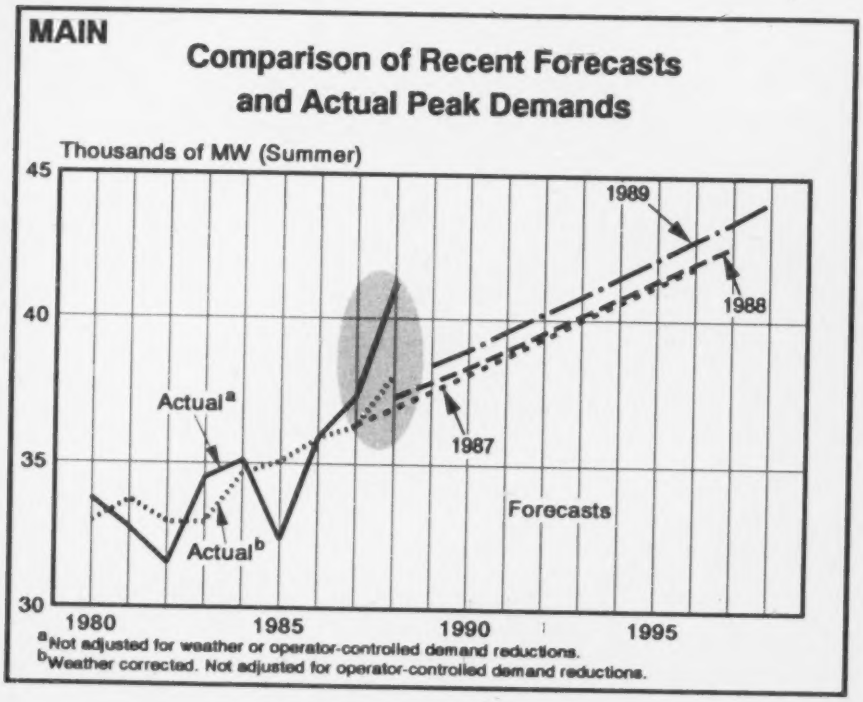
Actual annual energy use in MAIN also was higher than expected. Energy use increased by 6.7% over 1987, and was 5.2% above the 1988 forecast. The ten-year forecast for growth of annual energy use is 1.7%, the same as in the previous forecast.

Capacity Resources Adequacy

Generating capacity in MAIN is and will continue to be about 54% coal and 30% nuclear throughout the forecast period. In 1989, 53.7% of the electrical energy generated in MAIN will be from coal and 44.6% will be from nuclear. In 1998, coal will furnish 56.3% and nuclear 40.1% of the electrical energy generated in MAIN.

The generating reserve policy adopted by MAIN suggests that utilities maintain installed capacity at least 15 to 20% above the forecast peak demand in each year. This is equivalent to a capacity margin of 13 to 17%. Projected

MAIN



capacity margins are above minimum requirements throughout the forecast period, ranging from 22.9% in 1989 to 14.7% in 1998, considering load management, interruptible demand, and capacity sales and purchases.

During the next ten years, MAIN summer total internal demand is forecast to increase by 5,766 MW, while total installed capacity is expected to increase by 25 MW.

In general, the planned use of non-utility generators (NUGs) in MAIN is very small, totalling only 79 MW at time of summer peak in 1998. Planned load management is essentially constant at 40 to 50 MW throughout the period. Contractually interruptible demand is also essentially constant varying in the summer between 1,053 and 1,117 MW over the forecast period. This is about 300 MW more than projected in the previous ten-year forecast.

Inoperable capacity and scheduled maintenance are forecast to be near zero at time of summer peak.

Net purchases and sales change from a net sale of 259 MW in 1989 to a net purchase of 1,101 MW in 1998. Of purchases totaling 1,575 MW in 1998, 1,200 MW are from unknown sources. This reflects a recognition that additional demand management or generating capacity will be needed in 1998, but specific plans have not been finalized. Since substantial purchases from unknown sources occur only in the last year of the forecast period, there is ample opportunity to substitute short lead-time generating capacity options, increase generator availability improvement efforts, purchase NUG capacity, or reduce demand through load management or conservation.

In summary, MAIN expects to meet its increased summer peak demands by increasing contractually interruptible demand, by minimizing inoperable capacity and scheduled maintenance at time of summer peak, by reducing exports and increasing purchases, by adding short lead-time capacity, and by increasing load management and conservation.

Capacity adequacy in MAIN is assessed using loss of load probability (LOLP) analysis. The latest LOLP analysis, which covers the ten-year period ending in 1997, shows that without considering uncertainties due to weather and load forecast error, and with no more than 1,020 MW emergency imports from neighboring systems, capacity will be adequate to meet the MAIN expected LOLP criterion of one day in ten years until 1997. Considering uncertainties due to weather and load forecast error, MAIN may not be able to meet its LOLP criterion beginning in 1994. If demand follows projections, adequate time exists to augment load management practices or install short lead-time generation. However, if peak demands exceed forecasts, timing will be critical.

Transmission Adequacy

The transmission network in MAIN is adequate for reliable operation for both internal transfers and those involving adjoining Regions. Near-term operating studies, longer-term planning studies of interchange capability, and extreme disturbance studies, are conducted on a regular basis to assure that transmission capacity will continue to be adequate. Each of these studies includes participation by representatives from adjoining Regions to provide interregional coordination.

Few new major transmission lines are planned in MAIN during the 1989-1998 forecast period. However, one planned 345 kV line is experiencing delay. The Albion-E. West Frankfort line will complete a 345 kV tie from the Gibson plant of Public Service Company of Indiana to the Central Illinois Public Service Company transmission system at West Frankfort. This will constitute the third 345 kV circuit across

southern Illinois. The line is needed to reinforce the electric supply capability to a large area of southeastern Illinois. The line section was originally scheduled for completion in 1990; however, due to a lengthy regulatory approvals process, court action required before condemnation, and probable future court actions, the line will be delayed until 1992.

Future Issues Influencing Reliability

Some critical concerns in MAIN that have the potential to adversely impact electric system reliability include:

- Acid Rain Legislation – Since coal is the major fuel used in MAIN for electricity production, additional legislative or regulatory requirements for reduced sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions may adversely affect reliability of supply due to the following:

  – The maximum net output of most existing coal units would be reduced 2 to 5% if retrofitted with facilities for SO_2 removal.

  – The average availability of retrofitted units may also decrease.

  – The installation of emissions control equipment often requires lengthy unit outages resulting in less capacity to serve customer demand during the periods of retrofitting.

  – It may not be possible, nor economic, to retrofit some older units thus forcing premature retirement.

  – Unit capacity may be reduced due to burning low-sulfur coal.

  These factors could reduce the capacity available from existing coal units with the result that new replacement capacity will be required to maintain adequate levels of reliability. As capacity margins approach minimal levels in the last half of the forecast period, these concerns become of increasing importance. If new regulations are developed to control acid rain, the cost and lead time for the required replacement capacity must be given suitable consideration to maintain adequate system reliability.

- Application of Air Quality Standards to Maintenance Projects – With a net increase of only 25 MW in capacity planned in MAIN over the next ten years, it is extremely important that existing capability be maintained in operable condition. The Environmental Protection Agency's (EPA) application of New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) regulations to maintenance projects, as in the case of Wisconsin Electric Power Company (WEP), could erode the capability of existing units or force their early retirement. WEP has a five-unit Port Washington power plant with a 400 MW nameplate capacity. The 1989 MAIN rating is 270 MW. In July 1987, WEP requested permission from the Public Service Commission of Wisconsin to implement a maintenance program to return the plant's capacity to its 400 MW nameplate rating. The project was reviewed by the U.S. EPA who determined in October 1988, and reaffirmed in February 1989, that NSPS and PSD air regulations apply to the project. In November 1988, WEP filed a request in the Seventh Circuit Court of Appeals for review of the EPA's determination. The project is presently on hold pending the court review.

- Peak Demand Growth Above Forecast – MAIN's peak demand and annual energy forecasts are intended to have an equal probability of being high or low. The effects on reliability, however, are far from equal for actual peak demands higher or lower than forecast. If actual peak demands prove to be greater than forecast, utilities will encounter difficulty in adding transmission and generation capacity in a timely manner because of the present problems in siting and permitting. Concerns about the financing and timely recovery of costs for new generating capacity may also serve to delay new projects. Thus, the risk to reliability is accentuated. On the other hand, if peak demands are lower than forecast, there may be some adverse economic impact, but reliability would not be jeopardized.

- Capability of Manufacturers to Meet Utility Equipment Needs – With increasing numbers of utilities looking to combustion turbines as comparatively low-capital cost, short lead-time capacity, there has been concern for a number of years about manufacturers' ability to supply utility requirements beginning in the mid-90s. The same concerns now are voiced regarding large high voltage transformers and circuit breakers. A sudden influx of orders for this equipment might not only delay new projects, but would also delay the repair or replacement of equipment that fails. Delay in replacing failed equipment could seriously impact reliability.

- Operation With Lower Margins – Even though minimum reliability criteria will still be met, reliability levels will be lower than those in the past as generating capacity margins decrease toward minimal levels over the next ten years.

  As utilities operate closer to minimal capacity margins, increased long-term scheduled purchases and sales of capacity will replace the economy transactions which have predominated in the recent past. These capacity transactions will be more critical to reliability of service. Curtail-

ing capacity transactions due to transmission system emergencies can impact customer reliability far more significantly than the past curtailments of economy energy transactions.

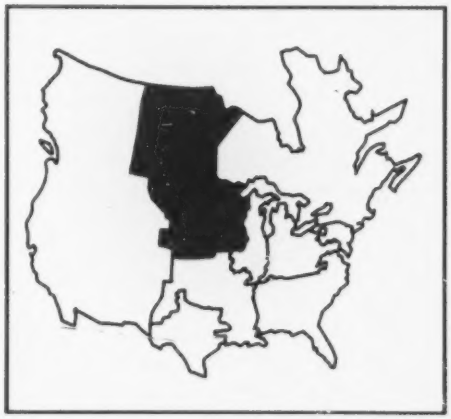
With less reserve capacity available, flexibility in dealing with emergencies is reduced. In the past, the MAIN electrical systems were capable of surviving multiple contingencies beyond the design level due to greater than planned margins. This capability will be less in the future.

- Increased Competition – Reliability of the interconnected electric systems requires the coordination of all connected utilities. Good coordination depends on sharing information in a timely fashion. Competition, on the other hand, could work in the opposite direction. For example, knowledge of unit outages and their anticipated duration might affect pricing of available energy or capacity. Therefore, pressures may develop to withhold or delay sharing such information. This could have a negative impact on electric supply reliability.

The Mid-America Interconnected Network (MAIN) consists of 12 regular member systems and one associate member. MAIN is a summer peaking Region serving a population of 18 million in a geographic area of 170,000 square miles encompassing Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin, and most of the upper peninsula of Michigan.

MAPP

MID-CONTINENT AREA POWER POOL



The existing and planned generation resources in the MAPP Region are anticipated to adequately supply the projected peak demand and annual energy requirements throughout the 1989-1998 assessment period. The capacity margin is projected to range from a high of 28.2% in 1989 to a low of 24.2% in 1996, and is expected to be adequate for the entire assessment period. A higher than projected peak demand could cause some reliability concerns near the end of the forecast period. Experience with load management in 1988 has reinforced confidence in this strategy as a means of delaying future capacity additions.

MAPP	Actual		Forecast		
	Summer	1988	1989	1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
MAPP-U.S.					
Summer Peak – MW		24,899	23,796	27,494	1.6
Winter Peak – MW		20,162	20,317	23,642	1.7
Annual Energy – GWh		121,737	119,456	142,664	2.0
Installed Capability (Summer) – MW		30,775	30,814	32,360	0.5
MAPP-Canada					
Summer Peak – MW		4,223	4,340	5,405	2.5
Winter Peak – MW		5,503	5,776	7,153	2.4
Annual Energy – GWh		29,926	30,888	38,416	2.5
Installed Capability (Winter) – MW		6,551	6,678	8,619	2.9
MAPP-Total					
Summer Peak – MW		29,122	28,136	32,899	1.8
Winter Peak – MW		25,665	26,093	30,795	1.9
Annual Energy – GWh		151,663	150,344	181,080	2.1
Installed Capability (Summer) – MW		37,325	37,515	40,986	1.0

Peak Demand and Energy

The 1988 summer peak demand in the MAPP Region was 29,122 MW. The U.S. portion of the Region achieved a new all-time summer peak demand of 24,899 MW, an increase of 7.5% over the previous peak demand in 1987. During the 1988 extended hot summer season, the Region exceeded the previous peak demand seven times. The record regional peak demand occurred on August 16, 1988.

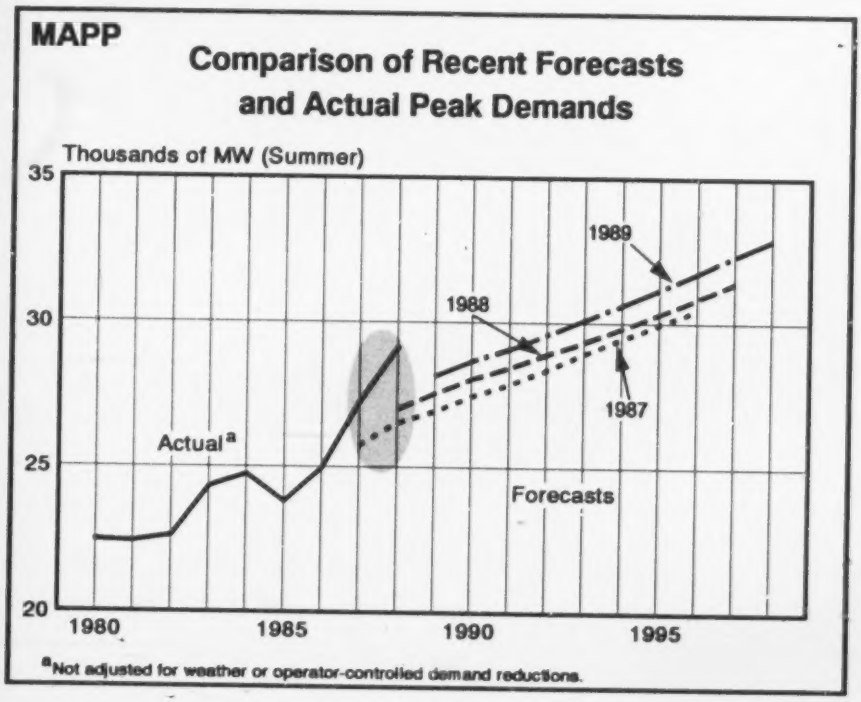
MAPP peak demand and annual energy forecasts are the sum of the individual utility forecasts. The projected 1.6% and 2% growth rates for MAPP-U.S. in summer peak demand and annual energy, respectively, are slightly higher than the previous year's projections.

MAPP-Canada continues to project somewhat higher growth in peak demand and net energy for load than the U.S. portion of the Region.

Actual peak demands and ten-year projections made in 1987, 1988, and 1989 are shown in the following figure.

The MAPP Region includes numerous smaller systems that are associate members of the Pool. Their peak demands, net energy for load, and generating capacity have been

MAPP



included in this report for completeness. These other systems served a combined peak demand of 650 MW in 1988. This is projected to increase to 810 MW by 1998.

MAPP utilities continue to actively pursue various programs to reduce growth in peak demands. In 1988, MAPP utilities reduced the peak demand by 625 MW through the use of load management and contractually committed interruptible demands. Due to the extended hot weather during 1988, some utilities exercised their load management ability to interrupt customer demands as many as 22 times. By 1998, utilities expect to be able to reduce peak demands by almost 1,500 MW through use of load management and interruptible demand. This appears to be a viable alternative strategy for delaying new generating capacity in the MAPP Region.

Capacity Resources Adequacy

The projected summer capacity margins in the Region, MAPP-U.S. and MAPP-Canada combined, are higher than the criteria for reliable supply in all forecast years with a minimum capacity margin of 24.2% occurring in 1996. The projected capacity resources are considered adequate to reliably supply projected peak demands and annual energy requirements over the assessment period.

The only major generating plant currently under construction is the 1,200 MW hydroelectric Limestone plant in Manitoba, Canada, which is scheduled for full operation by winter 1992.

In addition, a 280 MW lignite-fueled unit is undergoing licensing in Saskatchewan for service by the summer of 1992. The utilities are planning to meet future peak demand growth through the addition of peaking plants with over 1,000 MW of combustion turbines and combined cycle plants being proposed. The only new large coal-fired plants being proposed are a 400 MW unit in the United States in 1998 and a 276 MW lignite unit in Saskatchewan in 1996.

Through the purchase of existing capacity and the exchange of capacity on a seasonal basis, nearly 1,000 MW of new generating capacity have been deferred beyond 1998.

MAPP-U.S. and MAPP-Canada depend primarily on nuclear, coal, and hydro for electricity production. In 1988, 15% of the electricity produced was by nuclear generation, 18% by hydro, and 66% by coal. Less than 1% of the annual electrical energy was produced by oil or gas. This mix of electricity production is anticipated to remain essentially the same throughout the assessment period. Non-utility generators have a minimal part in the resource plans for MAPP and by 1998 will represent only about 1.1% of the total capacity resources.

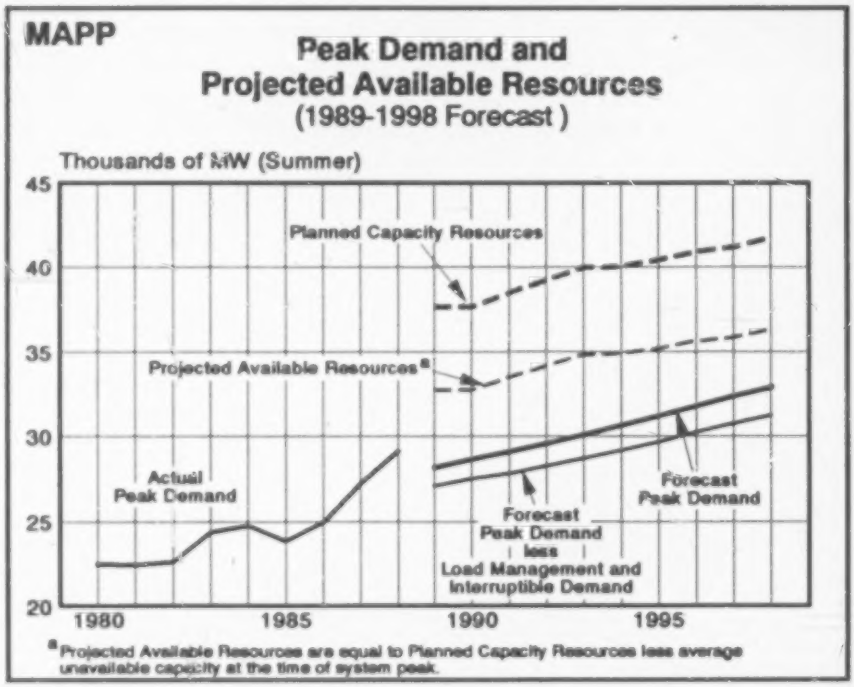
Projected peak demands and available resources for the 1989-1998 period are shown for the MAPP Region in the figure on the next page. Adjustments for expected forced and scheduled outages of generating capacity based on MAPP's average statistics over a five-year period have been used to calculate the projected available resources. This illustrates the adequacy of the MAPP Region's generation capacity to meet projected peak demand requirements. MAPP actually uses a more sophisticated method of determining required capacity margins in its regional reliability studies.

Transmission Adequacy

Transmission facilities as planned are judged to be adequate through the ten-year review period.

The MAPP utilities have 19,118 miles of ac and dc transmission lines 230 kV through 500 kV in service. Over the next ten years, plans call for the construction of an additional 1,435 miles of transmission lines, 230 kV and above.

Transmission loadings continue to be a concern for MAPP to MAIN transfers, but improvements on the lower voltage systems, currently under construction or planned, will reduce the number of instances of limited transfers on the higher voltage systems. Joint studies among utilities in MAPP and MAIN are currently under way to determine if additional transmission is justified to further increase transfer capability.



Reliability Issues

The major reliability issues in the MAPP Region are potential acid rain legislation, possible electromagnetic field regulations, increasing use of the transmission systems for contractually scheduled transfers, and demand exceeding forecast.

- Acid Rain Legislation – Legislative efforts to further reduce emissions of sulfur dioxide, nitrogen oxides, and other substances from coal-fired power plants increase the uncertainty of the adequacy of the MAPP generating capacity. About 8,000 MW (35%) of MAPP's coal-fired generating capacity was installed prior to 1975. This capacity would be subject to:
  - Extended outages to retrofit additional emission control systems,
  - Reduced capacity due to power consumption of the additional emissions equipment, and
  - Reduced availability because of increased complexity.
- Electromagnetic Field Regulations – The current concern about possible adverse health effects of electromagnetic fields could lead to regulations that have a potential of affecting the operation of MAPP's existing and planned transmission network. This could significantly reduce future reliability of supply.
- Transmission System Use – Increased utilization of the present capacity resources through seasonal diversity exchange agreements and capacity purchases increases the committed loadings on the transmission network thereby reducing the operating reliability margins. Further, greater dependency on coordination and planning among the utilities becomes paramount to maintaining reliability standards.
- Demand Exceeding Forecast – As peak demands continue to grow and capacity margins become minimal toward the end of the forecast period, the possibility of actual peak demands exceeding forecast could cause adequacy of generation supply concerns. If this occurs, the viable options will most likely be limited to increased load management and short lead-time peaking type generating capacity.

The Mid-Continent Area Power Pool (MAPP) membership includes 43 systems. There are 27 participants consisting of 11 investor-owned systems, eight generation and transmission cooperatives, three public power districts, four municipal systems, and one federal agency. The associate participants consist of two Canadian Crown Corporations, 13 municipals, and one investor-owned system. The MAPP Region covers all or portions of the states of Iowa, Minnesota, Nebraska, North Dakota, Illinois, Michigan, Montana, South Dakota, and Wisconsin; and the provinces of Manitoba and Saskatchewan. Total geographic area served is 890,000 square miles with a population of 16 million.

NPCC

NORTHEAST POWER COORDINATING COUNCIL

NPCC member systems face critical challenges concerning resource adequacy during the next decade. In response, they are planning on a variety of resource options. These include utility generators, non-utility generating capacity, expanded demand management programs, and purchases from other utilities. In New England, the resource additions required to maintain an adequate future supply are not yet committed. Reliability of the transmission network depends on the timely completion of planned reinforcements, location of future non-utility generators, and continued coordination in operations.

NPCC	Actual		Forecast		
	Summer	1988	1989	1993	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
NPCC-U.S.					
Summer Peak – MW		45,245	46,836	56,764	2.2
Winter Peak – MW		42,951	44,954	53,527	2.0
Annual Energy – GWh		250,132	254,540	301,044	1.9
Installed Capability (Summer) – MW		53,913	55,123	60,634	1.1
NPCC-Canada					
Summer Peak – MW		37,966	38,572	47,502	2.3
Winter Peak – MW		53,363	54,981	66,084	2.1
Annual Energy – GWh		291,515	301,564	369,326	2.3
Installed Capability (Winter) – MW		58,967	61,071	75,759	2.4
NPCC-Total					
Summer Peak – MW		83,211	85,408	104,266	2.2
Winter Peak – MW		96,314	99,935	119,611	2.0
Annual Energy – GWh		541,647	556,104	670,370	2.1
Installed Capability (Winter) – MW		114,881	119,697	138,113	1.6

Peak Demand and Energy

All five NPCC Areas experienced peak demands and annual energy use in 1988 above the levels in 1987, and also above forecast values for 1988. For the U.S. members of NPCC, summer peak demand in 1988 exceeded the 1987 level by 6.1% and was 5.1%, or approximately 2,200 MW, above forecast. For the Canadian members, the 1988/89 winter peak increased by 2.3% and was 3.1%, or approximately 1,600 MW, above forecast. Electrical energy use in 1988 by the U.S. members of NPCC increased by 4.6%, which is 2.4% above forecast. Electrical energy use in 1988 by the Canadian members of NPCC increased by 7.6% or 3.3% above forecast.

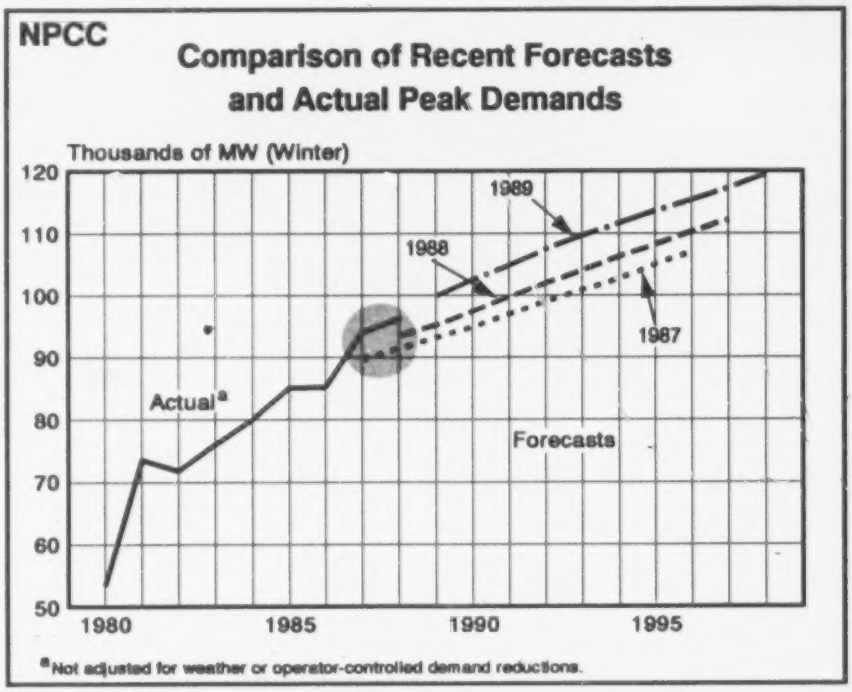
A comparison of actual winter peak demands for the NPCC Region and the forecasts made in 1987, 1988, and 1989 is shown in the following figure. The unadjusted actual peak demands for NPCC have exceeded the forecasts made just one year earlier for the last two years.

The 1989 ten-year forecast for NPCC peak demand and annual energy has been increased over the 1988 ten-year forecast. The current NPCC winter peak demand forecast for 1997, the last common year of both forecasts, is 4.6% or approximately 5,200 MW higher than last year's forecast.

Adequacy of Resources

A summary of the 1989-1998 net increases in NPCC resources by Area is shown in the table below.

Projected resources in New York (excluding Long Island), Ontario, Québec, and the Maritimes are adequate to meet forecast demands throughout the next ten years. However, this assumes that capacity plans, non-utility generator (NUG) projections, and demand management programs will be realized as scheduled. It also assumes that actual demand will not significantly exceed current forecasts.



An agreement recently finalized between the Long Island Lighting Company (LILCO) and New York State will result in the transfer of ownership of the Shoreham nuclear unit (809 MW) to the Long Island Power Authority, which is not permitted to operate the unit. The closing of Shoreham will result in continued marginal resource adequacy for Long Island until additional generating capacity is added on Long Island and additional transmission interconnection capability is installed in the early 1990s. The closing of Shoreham in a Region where capacity shortages may occur in the early 1990s is of great concern.

The five-year reliability assessment of bulk electric supply for the New England Power Pool (NEPOOL) indicates adequate capacity assuming: the forecast peak demands are not exceeded, and demand management programs and NUG capability reach or exceed the estimates of about 1,600 MW and 1,900 MW, respectively, by winter 1993/94. In addition, the generating capacity now under construction and the planned energy purchases must be available as scheduled. These include Seabrook 1 (1,150 MW by January 1990) and the Hydro-Québec Phase II firm-energy purchase (1,500 MW summer equivalent by September 1990).

NEPOOL estimates that it will need to add additional new resources beginning about 1993/94. However, no major utility capacity additions are currently planned beyond Seabrook 1. When additional resources prove to be required, they will most likely consist of expanded demand management programs, additional NUGs, increased pur-

Net Increase in NPCC Resources (%)
(1989-1998 Forecast)

Resource Options	New York	New England	Ontario	Québec	Maritimes[a]
Utility-Owned Capacity	22	21	63	79	100
Non-Utility Generators (NUGs)	42	20	5	4	0
Demand Management	16	38	32	17	0
Purchases from Other Utilities	20	21	0	0	0
Total	**100**	**100**	**100**	**100**	**100**

[a]New Brunswick and Nova Scotia

chases from other utilities, and relatively small utility generators. NEPOOL member utilities have identified sufficient possible resource options to meet their forecast peak demands.

A significant amount of non-utility generating capacity and demand management has been included in the projected resources for the next ten years, especially in New York and New England. Concerns regarding the dependability of these options on a long-term basis, and their availability during peak periods, increase the uncertainties inherent in resource planning. The next several years' experience with the availability of NUGs, and the effectiveness of utility demand management programs will significantly affect the long-term outlook for resource adequacy. In New York, the state mandated competitive bidding process will be used to provide additional generating units and demand management.

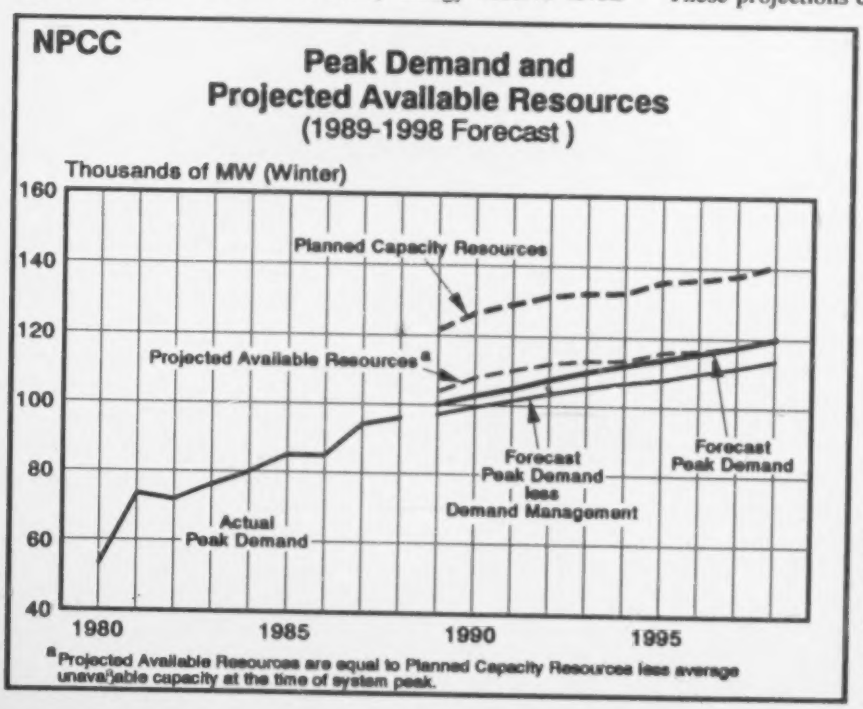
In Ontario, four 881 MW nuclear units are planned at the Darlington plant for service beginning in the fall of 1989 through early 1992. In addition, 550 MW of hydroelectric peaking generation on the Niagara River is planned for late 1998. Also included in Ontario Hydro's resource plan are approximately 2,800 MW of projected demand management programs by 1998.

In Québec, where the 1988 actual energy requirements were approximately 3% above forecast, energy reserve levels continue to decline as a result of the fifth consecutive year of adverse hydro conditions. As a result, construction of hydroelectric generating facilities is being advanced as much as possible. Two generating stations in the La Grande complex (La Grande 1 – 1,312 MW and Brisay – 382 MW) will come on line in 1994-95 and 1995, respectively, one year ahead of their previous schedule. Additional capacity (1,896 MW) at La Grande 2 generating station will be commissioned in 1991-92. Other resource options include: increasing demand management, operation of existing thermal generation, purchases from neighboring utilities, and advancing peaking units.

In the Maritimes, additional coal units are scheduled for installation throughout the forecast period.

The figure below provides a simplified comparison of the 1989-1998 projected winter peak demands and the projected available resources (PAR) for the NPCC Region. Adjustments for expected forced and scheduled outages of generating capacity based on average historical statistics have been used to calculate the PAR. Much more sophisticated methods are actually used by NPCC's Areas to assess their resource adequacy.

New York and New England remain the most heavily oil-dependent areas within the NERC Regions. Increasing demand and the lack of new non-oil-fired capacity are the major causes of the projected increase in utility oil use. These projections do not include the fuel burned by NUGs, much of which is gas and oil. The availability and transportation of natural gas for NUGs is a significant concern. There is also concern that NUGs may be more sensitive than utilities to changes in fuel price. If oil and natural gas prices suddenly increase, there may be less new NUGs built and the economics may drive some existing NUGs out of business, putting an additional strain on the limited capacity resources.



Transmission Adequacy

The New England, New York, Ontario, and New Brunswick systems meet the NPCC transmission criteria, and will continue to do so throughout the assessment period. When Hydro-Québec and Nova Scotia Power Corporation joined NPCC, it was with the understanding that although they did not satisfy all of the provisions of the NPCC criteria, contingencies on their

systems would not be allowed to have a significant adverse impact on the other NPCC systems. As a result, operating restrictions are currently in place which limit transfers between Hydro-Québec and the remainder of NPCC. An NPCC working group is presently assessing a major system enhancement program that Hydro-Québec has proposed to bring its system into conformance with the NPCC criteria.

The intraregional and interregional assessments of the proposed expansion of the HVDC interconnection between Hydro-Québec and NEPOOL have been successfully completed and a U.S. Presidential Permit covering this project has been issued. When completed in 1990, this interconnection will extend from the James Bay complex in northern Québec to Sandy Pond in eastern Massachusetts.

In the Canadian portions of NPCC, planned transmission line additions during the ten-year forecast period for voltage levels 230 kV and above total approximately 5,000 miles. By contrast, in the U.S. portion of NPCC, planned transmission additions total approximately 470 miles. This lack of construction of new transmission in NPCC-U.S. means that the existing New York and New England systems will have increased loadings as demand continues to grow. In the future, should the bidding process in New York result in additional generators being located in the western part of the state, additional transmission will be required.

Other assessment activities underway within NPCC include coordination and enhancement of the transient stability models used to analyze system performance, and a review of the reliability impacts of special protection systems and controls.

Operations

In recent years, loadings on the bulk transmission systems in NPCC have increased due in part to large economy energy transfers. To maintain reliable system performance, intraregional and interregional communications have also been increased. Through a "Procedure for Special Communications," weekly updates of interpool capacity margins are exchanged and conference calls are held among system operators in anticipation of emergency conditions.

The New England Power Exchange (NEPEX), the New York Power Pool (NYPP), Ontario Hydro, and the Pennsylvania-New Jersey-Maryland (PJM) Interconnection maintain an Interpool Computer Network. Hydro-Québec is in the process of joining the network and discussions are under way with utilities in the Maritime Area regarding their participation.

After a successful test period, a new operating procedure for Shared Activation of Reserves is now in place. NEPEX, NYPP, Ontario Hydro, and PJM participate in this procedure which enables these systems to recover more rapidly from the loss of major generation.

A working group on reactive power allocation has been working to identify those locations critical to voltage control within NPCC. When these locations are defined, appropriate operating procedures can be developed to address the constraints.

Recently completed investigations of power oscillations previously observed on the NPCC interconnected systems have verified the current transfer limits. This activity is being continued.

Coordination

Coordination in both planning and operations is the key to reliable system performance in NPCC. This includes coordination among NPCC's member systems and pools, and coordination with neighboring systems. As electric systems become more complex and interdependent, continued reliability will demand increased coordination.

NPCC has established a series of criteria, guides, and procedures within the context of the NPCC Reliability Assessment Program. These documents define minimum planning and operating requirements, and the means to implement, interpret, and monitor conformance. Studies to this effect are carried out by the Council's eight permanent task forces, working groups (established as required), and a full-time staff.

Coordination in operations within NPCC is achieved through a hierarchical system. Criteria, guides, and procedures developed at the NPCC level are expanded and implemented at the Area level by the two U.S. power pools and four Canadian member systems. Each of the U.S. pools and Canadian systems operates a centralized control center for economic dispatch, overall system monitoring, and control. In New England, control proceeds from the NEPEX dispatch center to satellite centers and then to the individual utilities. In New York, control proceeds from the NYPP dispatch center to the utilities. Voice and telecommunication systems link NEPEX, NYPP, and the Canadian control systems with each other and with neighboring systems in other Regions.

Interpool coordination agreements exist among the NPCC Areas and with neighboring systems. Further, NPCC is a party to Inter-Area Coordination Agreements with MAAC

and ECAR. Through these and a similar agreement among MAAC, ECAR, and the VACAR Subregion of SERC, studies are regularly conducted among MAAC, ECAR, and NPCC (MEN) and VACAR, ECAR, and MAAC (VEM). All are performed under the auspices of a permanent Joint Interregional Review Committee made up of representatives from ECAR, MAAC, NPCC, and VACAR.

The Northeast Power Coordinating Council (NPCC) represents 23 investor and publicly-owned utilities serving about 44 million people in a one million square mile area encompassing the Northeastern United States and Eastern Canada. In the United States, NPCC members participate in either the New England Power Pool (NEPOOL) or the New York Power Pool (NYPP), which constitute two of NPCC's five Areas. In Canada, Ontario Hydro, Hydro-Québec, New Brunswick Power, and Nova Scotia Power are province-wide systems and make up three of NPCC's Areas – Ontario, Québec, and the Maritimes.

SERC

SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL

Projected capacity margins in SERC are judged to be adequate during the review period based on current resource expansion schedules and peak demand and annual energy projections. However, several factors could affect the future margin between electric supply capability and peak demand. If peak demand exceeds current projections, a deficiency in generation supply capability could quickly develop. Maintaining adequate capacity margins depends on planned capacity additions coming on line as scheduled and continued high availability of existing generators. More than 17% of the planned capacity additions in the next ten years will come from non-utility sources. Also, the SERC systems continue to increase their conservation and direct control load management programs. Approximately 5,375 MW of load management is planned to be available for use by system operators to reduce demand during peak periods.

The SERC transmission systems are capable of supplying contractually scheduled capacity transfers and additional emergency transfers among the SERC subregions, and between SERC and other Regions. However, the increasing use of the transmission systems by many utilities simultaneously has resulted in heavy loadings on critical lines that limit interregional economy energy transfer capability. Coordinated planning and operations must continue among SERC and neighboring Regions to ensure that adequate reliability is maintained.

SERC	Actual		Forecast		
	Summer	1988	1989	1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		115,168	115,888	145,368	2.6
Winter Peak – MW		108,649	114,642	143,956	2.6
Annual Energy – GWh		593,948	610,556	764,550	2.5
Installed Capability (Summer) – MW		138,916	142,206	165,853	1.7

Peak Demand and Energy

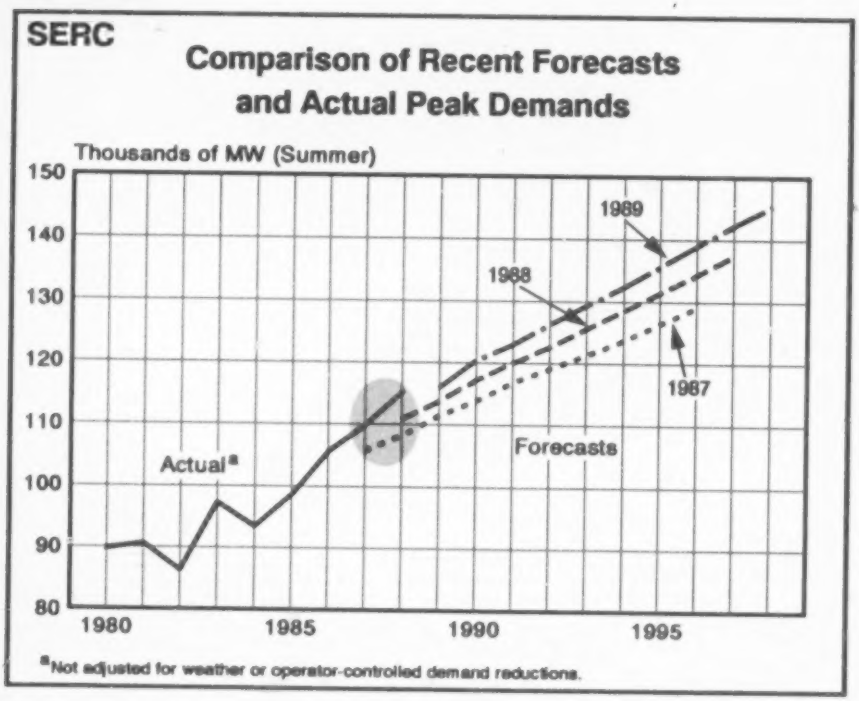
The SERC ten-year forecast has increased from that of last year, following increased energy growth (about 5% a year) that has occurred over the past three years. The following figure illustrates the growth in actual summer peak demand compared to ten-year peak demand projections made in 1987, 1988, and 1989.

The 1989-1998 forecast of average annual growth of summer peak demand has increased from last year's 2.4% to 2.6%. The summer peak demand projected for 1997 (the last common year of the past two forecasts) is 4,907 MW higher than projected last year. The winter peak demand growth rate has also increased from last year's 2.4% to 2.6%.

Load management programs continue to be pursued by member systems at about the same rate as projected last year. Operator controlled load management, which includes contractually interruptible customer demands, is expected to account for 5,375 MW of potential summer peak demand reduction by 1998.

Capacity Resources Adequacy

Capacity additions within SERC for the 1989-1998 period include 3,752 MW in coal-fired units, 4,712 MW in nuclear units, 2,437 MW in pumped storage units, 9,417 MW in combustion turbine/combined cycled units, and 1,580 MW in other categories. This results in total capacity additions of 21,898 MW. In addition, approximately 4,107 MW of new non-utility generators are projected, a decrease of 842 MW over last year's ten-year projection. Most of the large baseload units projected to come on line during this assessment period are well under construction with near-term operating dates. During the later years of the forecast period, because of system characteristics and regulatory and



financial concerns, many systems are planning on peaking or intermediate type capacity such as combustion turbines and combined cycle units, and capacity purchases from other utilities and non-utility generators.

Non-utility generators (NUGs) will increase significantly in the coming years for some SERC systems. Contractual provisions are being negotiated to ensure the long-term and high availability of NUG capacity during peak demand periods and to ensure the proper integration of NUG capacity into the transmission network to prevent degradation of system reliability. With proper coordination, NUG capacity is capable of becoming a viable option to help meet the peak demands of the 1990s and beyond.

Projected capacity margins in SERC are judged to be adequate during the review period, based on current generating capacity expansion schedules and peak demand and annual energy projections. However, if peak demand continues to exceed forecast, or if projected resources do not materialize as planned, capacity margins could become less than adequate in the latter portion of this assessment period. A comparison of projected peak demands and projected available resources is shown in the figure on the next page. Note that the difference between the Projected Capacity Resources and the Projected Available Resources is the five-year average unavailable generating capacity of about 15% in SERC at the time of peak demand. Successful implementation of the planned load management programs will be critical to the reliability of the SERC systems. Some additional capacity resources are also presently in the early planning stages. These additional units are expected to come on line in the latter half of this assessment period.

In addition to the installation of new capacity, modifications to existing units are under way and include unit upgrades, availability improvement programs, and reactivation of mothballed units. Electric supply adequacy would be adversely impacted by regulatory decisions or other factors that would restrict the availability of existing or planned generating capacity.

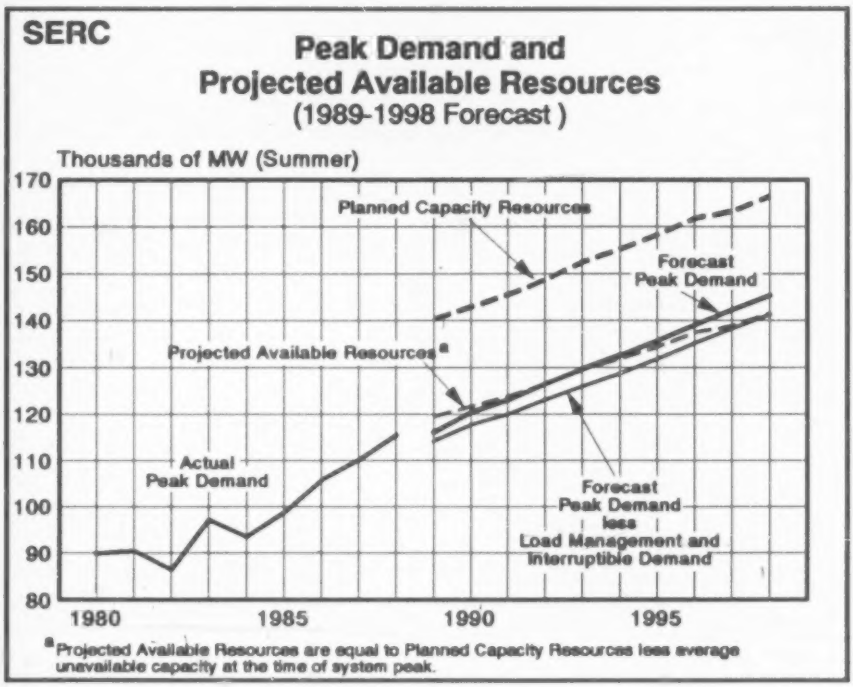
Transmission Adequacy

The existing transmission systems include 19,571 miles of 230 kV and over 7,608 miles of 500 kV transmission lines. During the review period, over 540 miles of 500 kV and approximately 1,940 miles of 230 kV lines are expected to be added.

Permitting of a key 500 kV line in Florida continues to be delayed because of a legal challenge to state electric and magnetic field regulations. The line, which was originally proposed for December 1987, is now indefinitely delayed. Until the line becomes operational, higher cost local generation may have to be operated to maintain system reliability under certain contingencies.

In December 1986, the final VACAR section of the Washington, D.C. 500 kV loop was completed. However, remaining sections of the loop will not be completed until 1994. This 500 kV loop is vital to the reliability of the bulk electric supply to the Washington, D.C. area and to the transfer capability among ECAR, MAAC, and SERC Regions.

SERC systems have coordinated transmission planning and operations to assure the continued use and expansion of a reliable transmission network. SERC is directly interconnected with the transmission systems in four other Regional Councils (SPP, MAIN, ECAR, and MAAC), and SERC members actively participate in inter- and intraregional transmission studies. Results of these studies indicate that existing facilities, along with those planned to meet the future reliability needs of the SERC subregions, will provide



adequate emergency transfer capability between SERC and other Regions and among the SERC subregions. All systems within SERC expect to meet SERC reliability criteria during the review period.

Operations

The bulk electric transmission network ten years from now will not be significantly different from the present day. The transmission systems are basically in place for most of the new capacity that is planned. Moderate demand growth and the sharing of generation capacity will reduce operating margins throughout this period. If NUG and load management programs become significant elements in electric supply, operating strategies will be modified in recognition of their specific characteristics. More frequent use of operating procedures involving these resources will become a normal part of system operations to ensure that system reliability is maintained.

Detailed near-term operating studies and longer range planning studies are made on a regular basis to ensure that transmission capacity will continue to be adequate. These studies involve representatives from each of the SERC subregions and from adjacent Regions to provide interregional coordination.

Reliability Issues

The key reliability issues of most concern to the SERC systems are:

- Transmission Wheeling – During 1988, the SERC systems have continued to voluntarily participate in capacity transfers among utilities located within or interconnected with SERC. These transactions involve both economy energy and capacity exchanges, and were subject to the ability to maintain an adequate level of reliability for serving customers and meeting scheduled interchange agreements with neighboring utilities.

  The impact of increased transmission wheeling on system reliability continues to be a major concern to SERC members. Transmission wheeling remains a complex and unresolved part of the Federal Energy Regulatory Commission's initiatives on competitive bidding related to qualifying facilities and independent power producers.

- Adequacy of Capacity – As presently planned, generation capacity in SERC over the next ten years will be adequate to serve the projected peak demands and annual energy requirements throughout the assessment period. Some utilities are evaluating short lead-time resource additions that could be placed in service by the end of this period. To meet the future supply-side resource needs, peaking, combined cycle, and integrated coal gasification combined cycle units are being considered. Although adequate capacity margins are anticipated, regulatory decisions restricting the availability of nuclear or coal units could adversely affect supply adequacy.

  Non-utility generators will become a significant source of new capacity in the coming years for some member systems. At issue is whether non-utility generators will match traditional utility generators in reliability, dispatchability, and diversity of fuel supply. Although many reliability questions will be answered by experience, the relatively small size of the NUG units, their experience to date, and their location near load centers indicate that NUGs have the potential to provide reliable service. Contracts with non-utility generators are including considerations of reliability and operability factors to ensure the long-term viability of non-utility generation.

SERC

Load management, including contractually interruptible demands, is key to the adequacy of resource plans in SERC. More than 5,375 MW of utility-controlled load management is projected to be available by 1998.

- Environmental Issues – The major environmental issues causing concern among the systems in SERC are acid rain and electromagnetic field (EMF) effects.

Proposed acid rain legislation would have a significant impact on the availability of existing fossil generating units. Many systems in SERC continue to be actively involved in projects to identify the significance of potential acid rain regulations to system reliability.

On January 18, 1989, Florida became the first state to regulate power line magnetic fields and the seventh state to regulate electric fields. The Florida Environmental Regulation Commission (ERC) adopted the standards to protect public welfare. The ERC concluded that a review of present scientific data found no conclusive evidence of danger or hazard to public health at existing EMF levels associated with transmission lines. However, the ERC felt it prudent to lower long-term exposure to the population by limiting field strengths at the edge of power line rights-of-way (ROW). The standards are as follows:

– Existing lines are allowed to operate as is.

– Florida Power Corporation's Lake Tarpon-Kathleen 500 kV line, certified before the Florida standards but not yet under construction, must meet standards specified by the Governor or Cabinet during the certification process. These certification standards are more stringent than the ERC's standards for new lines.

– New 500 kV line standards are 10 kilovolts/meter (kV/m) maximum electric field strength within the ROW, and 2 kV/m maximum strength at the edge of the ROW. New 230 kV lines or smaller must meet standards of 8 kV/m maximum electric fields within the ROW, 2 kV/m maximum electric fields at the edge of the ROW, and 150 milligauss (mG) magnetic field strength at the edge of the ROW.

– For new double circuit 500 kV lines, the maximum magnetic field at the edge of the ROW is 250 mG.

Florida's utilities feel the ERC standards are a workable compromise. These standards may be challenged by citizen groups.

In addition, the ERC asked that Florida research be undertaken to investigate means of lowering field strengths. The Florida Coordinating Group has agreed in concept to provide funding for such an effort.

SERC membership includes 29 systems located in nine states in the southeastern United States. SERC is divided into four diverse Subregions covering an area of 345,650 square miles which are identified as Florida (the Florida peninsula), Southern (the geographical area of the Southern electric system), TVA (the Tennessee Valley Authority area), and VACAR (the Virginia-Carolinas area). Total population in the Region is about 26 million.

SPP

SOUTHWEST POWER POOL

Above average temperatures overcame the still weak petroleum and agriculture related economy to cause a 1988 summer peak demand 2.1% greater than that forecast. This was the third consecutive year of significant peak demand growth resulting in peak demand forecasts for 1989 through 1998 greater than those forecast in previous years. Average annual energy use for the next decade has also been increased.

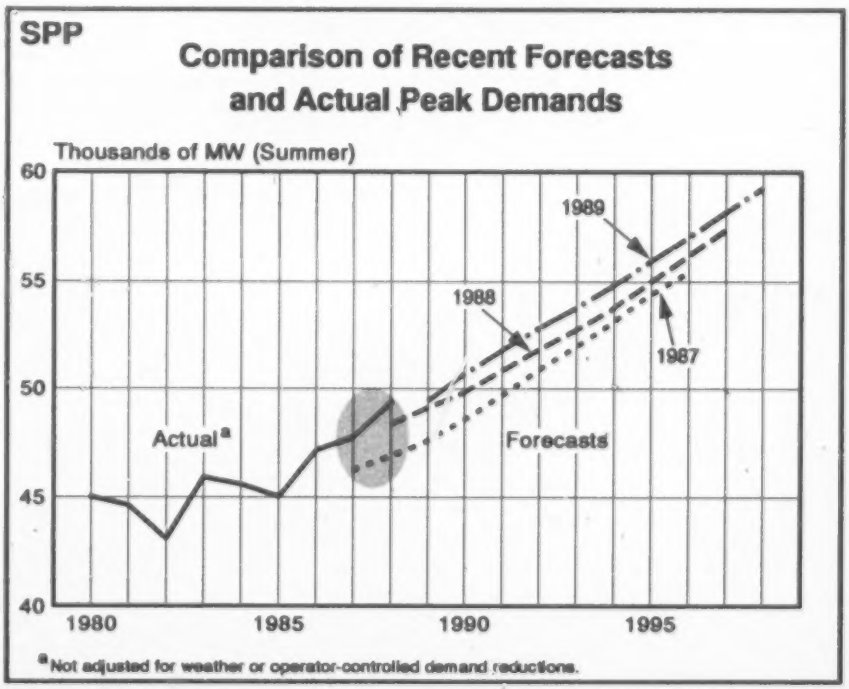
For this assessment period, generation capacity appears to be adequate until 1997. The transmission system appears to be adequate for all interregional and intraregional transfers. There are no new baseload units planned.

SPP	Actual		Forecast		
	Summer	1988	1989	1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
Summer Peak – MW		49,356	49,430	59,295	2.0
Winter Peak – MW		35,649	37,041	45,505	2.3
Annual Energy – GWh		237,179	237,963	285,543	2.0
Installed Capability (Summer) – MW		66,221	66,327	68,584	0.4

Peak Demand and Energy

In four of the five years between 1981 and 1985, peak demand decreased from the previous year. However, since 1985 the Southwest Power Pool (SPP) has experienced three consecutive years of significant peak demand growth. In spite of a still depressed agriculture and oil industry economy – Texas, Oklahoma, and Kansas still lead the nation in the number of bank closures – above normal temperatures in the 1988 summer brought about a 3.4% increase in demand over 1987. This compares with an average annual increase for the five-year period between 1983 and 1988 of only 1.5%. Recent actual peak demands and ten-year projections made in 1987, 1988, and 1989 are shown in the adjacent figure.

In 1988, the peak demand of 49,356 MW was 2.1% greater than the forecast made a year earlier. The trend for the last three years has resulted in a projection of average annual peak demand growth between 1989 and 1998 of 2% to 59,295 MW. The forecast of the 1989 peak demand was increased by 310 MW since last year. This slightly greater forecast for annual peak demands results in



SPP

a 1997 peak demand 793 MW greater than that forecast last year. While SPP is projected to grow at an average annual rate of 2% between the years 1989 and 1998, the subregions of SPP are projected to increase at a rate of 2.4% for the Northeast, 2.1% for the West Central, and 1.8% for the Southeast.

Annual energy use is forecast to increase at an annual rate of 2%. This compares with a forecast rate of 1.9% in last year's projection.

Capacity Resources Adequacy

Presently, SPP has ample generating capacity to serve its peak demand requirements. This is evident by SPP being a net exporter of energy for the past two years.

No new baseload generation is planned for the forecast period. However, 2,572 MW of mothballed units to be returned to service, 1,165 MW of new combustion turbine and combined cycle units to be added, 500 MW of NUGs to be installed, and 1,874 MW of retirements and reratings of existing units will increase the 1988 capacity resources of 66,221 MW to 68,584 MW by 1998.

With the present demand and capacity projections, the capacity margin will be adequate until 1997 when the Pool will be deficient by 691 MW below the SPP criteria margin of 16.7%. Should a total of 872 MW of load management and interruptible demand not materialize, then the Region could run short in 1996. Projected peak demands and available resources for the 1989-1998 period are shown for SPP in the adjacent figure.

Over the forecast period, the SPP fuel mix remains fairly constant with coal supplying 55%, gas and oil 27%, and nuclear roughly 15% of the total fuel requirements. At the present time, there are adequate supplies of fossil fuels for the forecast period. However, regulatory action could result in serious capacity problems for the utilities of SPP with such a significant ratio of coal, gas and oil, and nuclear generation.

Transmission Adequacy

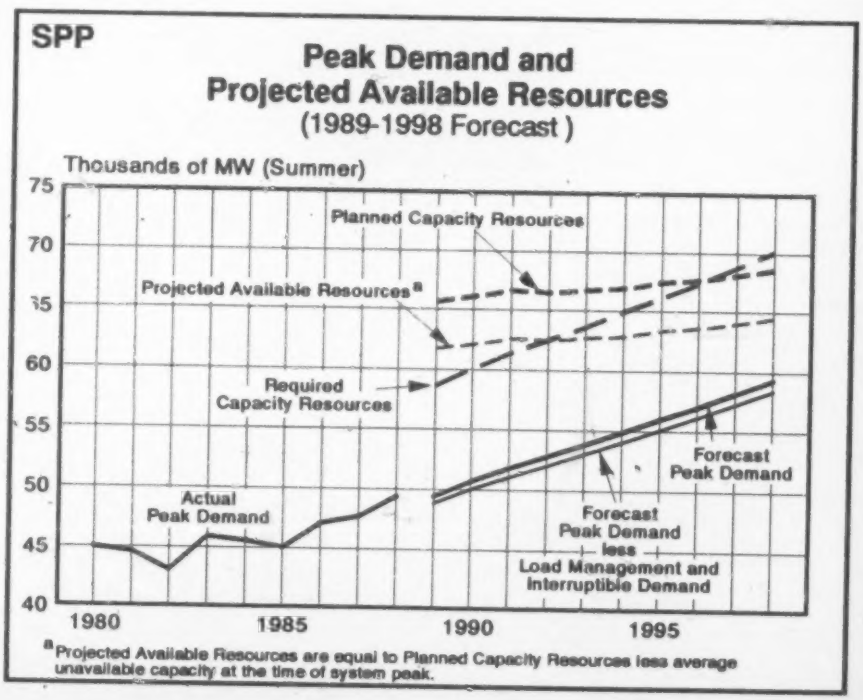
Since last year's assessment the only major transmission line placed in service was the 135-mile 345 kV line between Flint Creek generating station in the extreme northwest corner of Arkansas and the Morgan substation near Springfield in southwest Missouri.

During the next five years, it is projected that 401 miles of 230 kV, 270 miles of 345 kV, and 10 miles of 500 kV will be installed. Between 1994 and 1998, an additional 111 miles of 230 kV, 31 miles of 345 kV, and 154 miles of 500 kV are planned. In addition, a 600 MW dc tie between ERCOT and SPP, located in northeast Texas, is planned to be in service in 1992.

The transmission network as planned is adequate and over the assessment period there are no major transmission bottlenecks to economy or emergency transfers. During the ten-year review period, increased amounts of capacity transfers will decrease the amount of available transmission system transfer capability.

Operations

The transmission network is designed to be reliable for all single contingency conditions. There are several isolated local area limitations that are closely monitored, and when required, operating guidelines are implemented to reduce line loadings under contingencies. At times, parallel path or loop flow in the Middle South Electric Systems, TVA, and Southern Company interface must be closely monitored and controlled.



Regional and Interregional Coordination

SPP continues to work with adjacent Regional Councils in studying economy transfers and transfer capabilities for both near term and future years. Studies to date show non-simultaneous, first contingency transfer capabilities from SPP to MAIN of 1,150 MW, and 2,650 MW from MAIN to SPP. SPP can export roughly 2,400 MW to SERC or import as much as 3,450 MW from SERC. With MAPP, SPP can export 1,075 MW and import 1,900 MW. Recent studies indicate incremental transfer capabilities will increase between SPP and SERC during the ten-year review period. During the same period, incremental transfer capabilities between SPP and MAPP, and SPP and MAIN will decrease because of an increase in the level of scheduled capacity transfers between these Regions.

The 220 MW dc interconnection with ERCOT remains very important as lower fuel prices in Texas allow import of economy energy as well as output from jointly-owned generators. Transfer capability between SPP, in the Eastern Interconnection, and the Western Interconnection is by means of two 200 MW dc ties.

Work has commenced on acquiring a new SPP computer communications system that will allow faster and more efficient sharing of information among member systems. This computer system will initially be a computer-directed dial-up communications system.

A SPP guide on non-utility generation has been issued to member systems to insure that all NUGs, as planned and operated, do not pose a reliability risk to the Pool or its members.

Task forces have been organized to review load forecasting bandwidth methodology and implementation and to review the appropriateness of the existing operating reserve guide. This guide addresses minimum operating reserves required to maintain adequate and secure operations within the SPP Region.

Reliability Issues

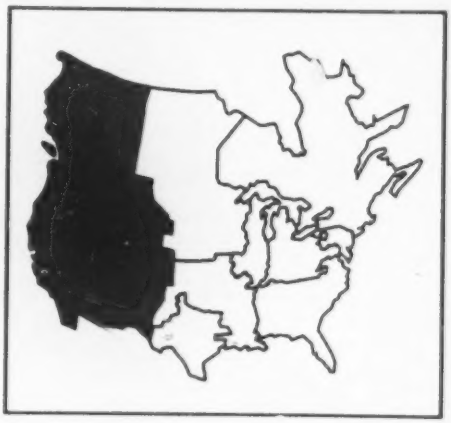
A number of issues concern the SPP members. Perhaps the most significant is the impact of greater than anticipated peak demand growth. If the 2% projected peak demand were to increase by only one percentage point to a rate of 3%, if only 200 MW of NUGs materialize instead of the projected 500 MW, and if purchases amount to only 100 MW instead of 200 MW, then it would appear that SPP will be short of meeting its existing capacity margin requirements prior to 1994. If accelerated demand growth does materialize, SPP will return a number of mothballed units to service sooner than planned, and will install combustion turbines and combined cycle units earlier than anticipated. With 55% of the electrical energy predicted to be supplied by coal, legislation on acid rain becomes very significant. If the regulations are too severe, then a number of existing older coal-fired units may be retired. Also, with approximately 15% of the energy to be produced by nuclear fuels, legislation concerning nuclear waste could have a severe impact in SPP.

Reliability is a concern with any regulations that involve transmission service and the use of the SPP transmission system by NUGs and others. The utilities that own and operate the transmission network must be permitted to operate that network in the most reliable manner with economic generation considerations being determined by the utility owners.

The Southwest Power Pool (SPP) includes 43 electric power suppliers serving customers in the states of Kansas, Oklahoma, Missouri, Arkansas, Mississippi, Louisiana, Texas, and New Mexico. The membership is composed of 17 investor-owned utilities, 12 municipal systems, ten generating and transmission cooperative systems, three state authorities, and a federal agency. SPP currently serves more than 6.6 million customers and covers a geographic area of 500,000 square miles containing a population of over 25 million.

WSCC

WESTERN SYSTEMS COORDINATING COUNCIL



The WSCC member systems are optimistic regarding the outlook for reliability within the Region. WSCC's supply of electricity and the transmission network are projected to be adequate in serving the forecast growth in customer requirements during the next ten years. Although challenging issues such as competition, transmission service, and restructuring of the industry are emerging, the WSCC members believe that these issues can be reasonably managed to avoid degradation of reliability through the cooperative efforts of utilities, non-utilities, and the regulatory community.

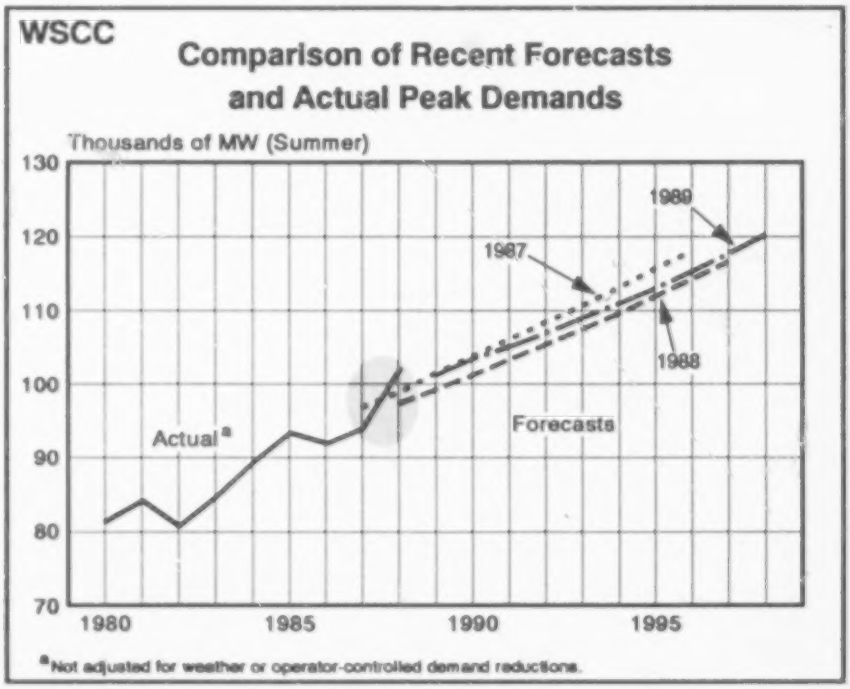
WSCC	Actual		Forecast		
	Summer	1988	1989	1998	Growth Rate
	Winter	1988/89	1989/90	1998/99	(%/year)
WSCC-U.S.					
Summer Peak – MW		90,551	89,247	104,508	1.8
Winter Peak – MW		88,523	85,256	98,771	1.6
Annual Energy – GWh		522,455	537,481	627,050	1.7
Installed Capability (Summer) – MW		127,402	125,154	133,406	0.7
WSCC-Canada					
Summer Peak – MW		10,857	11,540	14,642	2.7
Winter Peak – MW		13,734	14,038	17,893	2.7
Annual Energy – GWh		82,154	85,559	109,502	2.8
Installed Capability (Winter) – MW		17,711	18,053	20,011	1.2
WSCC-Mexico					
Summer Peak – MW		705	762	1,424	7.2
Winter Peak – MW		527	521	963	7.1
Annual Energy – GWh		3,472	3,779	7,278	7.6
Installed Capability (Summer) – MW		1,030	1,030	1,734	6.0
WSCC-Total					
Summer Peak – MW		101,874	101,219	120,254	1.9
Winter Peak – MW		102,784	99,614	117,627	1.9
Annual Energy – GWh		608,081	626,819	743,830	1.9
Installed Capability (Summer) – MW		146,312	144,127	154,898	0.8

Peak Demand and Energy

WSCC's 1989-1998 forecasts of peak demand and annual energy growth rates are somewhat reduced from last year's ten-year forecasts. However, the Region's 1988 summer peak demand, winter peak demand, and annual net energy for load are above their 1988 forecast values by 4.7%, 7.6%, and 1.9%, respectively. Both WSCC's summer peak demand and annual net energy for load are forecast to grow at 1.9% per year over the 1989-1998 forecast period. The following figure illustrates actual peak demands from 1980 to 1988 and a comparison of recent peak demand projections for the WSCC Region.

Capacity Resources Adequacy

The net generation additions (14,899 MW) projected over the next ten years are considerably less than the net generation additions (34,636 MW) placed in service during the past ten years. This significant reduction, by a factor of more than 2.3, in planned resource additions is in response to the lower demand growth projections of recent years and the surplus resources available throughout the WSCC Region. Non-utility generation represents 34.2% (5,090 MW) of the planned ten-year net generating capability additions. Although non-utility generation additions represent a significant percentage of the total planned resource additions, these resources will account for only 6% of the Region's total resources by 1998.



California leads the WSCC Region in projected non-utility generation additions. Non-utility generation is projected to increase from 3,495 MW to 7,020 MW over the next ten years in the California-Southern Nevada Power Area, reflecting a 101% increase.

Due to the financial risks associated with the large capital expenditures required to build new generating facilities, utilities in WSCC are reluctant to commit to large new projects. As a result, "flexibility" is a key element in the planning process to minimize the commitment to large capital expenditures. Flexible options being considered by WSCC member systems to maintain an adequate load-resource balance include conservation and load management programs. As an example, Northwest utilities are focusing on conservation programs such as residential weatherization, water heater wraps, revision of building codes, commercial energy audits, and industrial modernization incentives. Some conservation savings have already been achieved, and the impact of the implementation of additional conservation measures is reflected in the load forecasts.

Deferral of new resources will postpone the retirement of older generating plants including gas- and oil-fired units, thereby extending the utilization of gas and oil as primary fuels. Heavy interarea transfers of hydro and coal-fired energy will continue as a means of reducing utility gas and oil requirements and lowering the cost of electricity to the consumer.

The generating capacity margins of WSCC range from 27% to 19% over the assessment period and are judged to be adequate to reliably meet customer demands.

Transmission Adequacy and Operations

The WSCC transmission system is adequate to accommodate anticipated firm and most economy energy transfers during the ten-year period (1989-1998).

WSCC member systems are making a concerted effort to maintain an acceptable level of existing and future system reliability while accommodating higher transfer levels. Operating restrictions (defined by nomograms) are required to limit simultaneous imports of electricity into California. These operating restrictions have been implemented to achieve acceptable system performance in the event of a disturbance.

Several utilities within the Region are proceeding with plans to install phase-shifting transformers in the transmission lines connecting Utah/Colorado and Arizona/New Mexico. The phase shifters are scheduled to be placed in operation during 1989-1990 and are expected to significantly mitigate the Region's major loop flow (parallel path flow) problems.

WSCC

Regional Reliability Issues

The following are important issues which must be responsibly managed to avoid degradation of system reliability within the WSCC Region:

- Deregulation and Increased Competition – The availability of surplus generation in some areas has led to increased competition between utilities to serve markets, particularly in California. Increased competition may result in increased utilization of transmission facilities with resulting reductions in transmission margins unless new facilities are added. As competition increases, and as utilities respond to competitive forces, they may choose to reduce communication and cooperation with competitors. This could lead to delays in reporting and communicating planned new facility additions to protect a competitive advantage. As a result, effective planning on a regional scale could suffer and future system reliability may be adversely affected. Industry-wide deregulation could magnify this problem.

- Economics vs Reliability – In planning electric systems, the utility industry has always recognized that economics and reliability must be considered collectively. Pressure to minimize rate increases, or in some cases, reduce rates in order to remain competitive will result in a reduction in capital expenditures and operating expenses and an increase in the use of existing facilities. One consequence will be an increase in economy and firm transfers on the transmission system and the use of complex operating nomograms to maximize the use of the existing transmission network. These practices reduce the amount of operating margin designed into the system. As system operating margins decrease, the relationships between the many factors which affect reliability become more complex and require increased care and consideration in implementing measures to assure reliability.

- Changes in Planning Criteria – Due to the evolving economic considerations resulting from the trend towards deregulation, individual utilities and/or groups of utilities may choose to modify their internal reliability criteria to become more competitive. Efforts to compete by reducing capital expenditures include the examination of planning criteria and equipment rating criteria. One question frequently asked is "What are the consequences of not designing the system to withstand certain low probability events?" The answers to this question are used to make capital expenditure decisions. The probability of the event occurring does not change, only the method of dealing with it. In the past, the contingency may have been dealt with by installing additional facilities. It is now more likely to be dealt with by developing an operating procedure that minimizes the consequences of the contingency. This practice results in reduced capital expenditures and increases the utilization of existing facilities at some slightly increased risk. The intent is to apply more sophisticated techniques in evaluating costs versus risks while avoiding any measurable reduction in reliability. While this may lead to reduced reliability within some individual systems, the continued adherence to WSCC criteria will minimize effects on other systems and the Region as a whole.

- Non-Utility Generators (NUGs) – NUGs account for 34.2% of the planned net resource additions in the WSCC Region during the next ten years. There is no inherent technical reason why non-utility generation should degrade overall system reliability. However, non-utility generators must be operated to the same standards as utility generation, particularly in response to disturbances affecting the interconnected electric system. An adequate amount of NUG generation must also be equipped with special devices, the same as those used by utilities, which help damp oscillations that may occur during system disturbances. As most WSCC utilities have adequate capacity margins at present, avoided costs are low and fewer NUGs are being proposed. This trend will likely continue for several years.

- Parallel Path Flow – Parallel path flow affects both economics and reliability. It can result in a portion of the transmission system being very heavily loaded and can cause the system to be operated with less margin and incur higher losses. If a system wants to fully utilize its transmission capacity, the existence of parallel path flow could necessitate the installation of new facilities, promote the reliance on additional special protective schemes to raise the transfer capability, and require the development of additional complex operating nomograms. Several WSCC members are installing phase-shifting transformers to mitigate parallel path flow problems.

Northwest Power Pool Area

The Northwest Power Pool (NWPP) Area is comprised of the states of Washington, Oregon, Idaho, Utah, portions of Montana, Wyoming, Nevada, and California; and the Canadian provinces of British Columbia and Alberta. Winter generating capacity margins for this winter peaking area range between 23% and 15% for the next ten years.

The NWPP Area continued to experience relatively mild winter weather conditions in 1988. It is expected that a severe winter could substantially increase peak demand. Local regulatory bodies within the Puget Sound area in

Washington now require the curtailment of wood-burning stoves during air stagnation conditions to control particulate emission. This could further increase peak demand depending upon the extent to which electricity serves as a backup heating source.

Due to lower demand growth rates over the past ten to fifteen years, major transmission additions between generation and load centers in the NWPP Area have not been required. Utilities are now studying potential voltage instability problems in the populous load centers under cold winter peak demand conditions which may not be correctable through increased reactive support. Major transmission additions may be required by the mid-1990s to correct this problem. Conservation, local generation, and demand management alternatives are also being studied.

The third 500 kV AC Pacific Intertie between the Pacific Northwest and California is scheduled for completion in 1992. This facility will increase the rating of the Northwest-Southwest AC Pacific Intertie from 3,200 MW to 4,800 MW. The project consists of a new 500 kV line extending from southern Oregon to central California. The present Northeast/Southeast islanding scheme which separates the WSCC system into two islands for simultaneous loss of the two existing AC Pacific Intertie lines is not currently planned for use after the addition of the third AC Pacific Intertie.

The HVDC Pacific Intertie which extends from the Pacific Northwest to southern California was uprated from 2,000 MW to 3,100 MW by increasing the capacity of the DC line terminal facilities.

Work is in progress to increase the transfer capability of the existing interconnection between the Pacific Northwest and British Columbia. A 300 MW uprate from 2,000 MW to 2,300 MW is planned for 1989. During the fall of 1990, B.C. Hydro is planning to install a 400 MVA phase-shifting transformer in the B.C. Hydro to Bonneville Power Administration 230 kV interconnection. Additional 230 kV interconnections between Canada and the United States are being studied. These new interconnections will be located north of both Seattle and Spokane, Washington, and are tentatively scheduled to be placed in service during 1992 and 1995, respectively.

A new 500 kV transmission line during the 1993 time period from south-central Idaho to east-central Nevada is being studied by Idaho Power Company.

The Bonneville Power Administration (BPA) is undertaking a thorough review of its reliability criteria. As part of the review process, input is being obtained from BPA's utility customers, state regulatory bodies, environmental groups, and other outside interest groups. An indication of the level of reliability desired by those served by BPA is an important factor that will be considered during the review. The review is scheduled for completion in the fall of 1989.

Rocky Mountain Power Area

The Rocky Mountain Power Area consists of Colorado, eastern Wyoming, and a small portion of Nebraska and South Dakota. Summer generating capacity margins range between 27% and 22% for the next ten years.

The 1988 summer peak demand was 1.3% greater than the 1987 peak and 1.9% less than forecast. The lower than forecast peak demand is believed to be due, in part, to unseasonably cool temperatures during July, the month in which the summer peak demand historically occurs. In addition, area economic conditions could have contributed to the less than projected peak demand.

No major generating facilities were placed in commercial service during 1988 in the Rocky Mountain Power Area. Non-utility generation contributed approximately 70 MW of additional capacity within the Area. Five combustion turbines with a combined rating of 325 MW were deactivated during the 1988 winter season. It is anticipated that 225 MW of this combustion turbine capacity will be permanently removed from service during 1989.

To relieve the heavy loading on the transmission system northeast of Denver, plans are under way to uprate and rebuild certain existing line sections during the next two to three years. These plans include the Cherokee-Fort Saint Vrain 230 kV and Midway-Nixon 230 kV lines scheduled for operation in the first quarter of 1989, the Ault-Fort Saint Vrain 230 kV line scheduled for operation during the second quarter of 1990, and the Sidney-North Yuma 230 kV line scheduled for operation in the third quarter of 1992.

To meet the need for increased transfer capability across Wyoming, the Dave Johnston-Spence-Thermopolis 230 kV line was placed in service during 1988 and a 230 kV line between Spence and the Jim Bridger area is planned for service in 1990.

The existing 138 kV transmission system connecting northern Colorado and Utah is very heavily loaded at times due to a combination of firm transfers, economy transfers, and parallel path flow. Construction of a new 345 kV line between Colorado and Utah began in 1988 and the line is scheduled for service during the first quarter of 1990.

Parallel path flow continues to cause serious operating problems for utilities in the Region. In order to mitigate parallel path flow concerns, five phase-shifting transformers will be installed in southern Utah and southwestern Colorado. These phase-shifting transformers will provide bi-directional control of up to 500 MW of major parallel path flow through southern Nevada/California. They will require coordinated operation by their owners in order to permit full utilization of their capability. The southwestern Colorado phase-shifting transformers are scheduled for service during the third quarter of 1989. The southern Utah phase-shifting transformers are expected to be in service in 1990.

Continued reliance on remedial action schemes within WSCC for the purpose of increasing transmission system transfer capability exposes the electric system to potentially severe consequences for incorrect operation of such schemes. While there is adequate transmission capacity within the Rocky Mountain Power Area, there are concerns with the growing complexity of interconnected operation with other areas.

A new NUG bidding process with improved operating criteria is being implemented in the Colorado portion of the Rocky Mountain Power Area. While these Qualifying Facility tariff provisions are expected to improve dispatchability and availability of NUGs, there is still uncertainty as to the actual amount of NUG capacity that will be installed and the long-term availability of such capacity. At the present time in the Rocky Mountain Power Area, there is approximately 700 MW of additional NUG under purchase contracts. This represents approximately 85% of the new generating capacity planned in the Rocky Mountain Power Area through 1995. Since some NUG projects are economically linked to the profitability of another industry and fuel sources may be subject to substantial price escalation, the amount of NUG that will actually be financed and constructed is difficult to predict.

Generating capacity installed in the Rocky Mountain Power Area is surplus to the near-term demand requirements within the Area. Approximately 1,000 MW of excess coal-fired generating capacity is available for area load growth and export to other areas. The export of surplus power is limited by the transmission capacity to outside areas; however, the Colorado/Utah phase-shifting transformers, the Sidney and Miles City dc ties, and a new transmission line between Utah and Colorado, planned for the early 1990s, will provide needed additional export capability. Current demand forecasts indicate that the surplus generating capacity will be available until the mid-1990s before being absorbed by area load growth. The availability of surplus generating capacity will be affected by both long-term export commitments to other areas and the amount of NUG capacity that is actually constructed and placed in service.

Arizona-New Mexico Power Area

The Arizona-New Mexico Power Area consists of Arizona, most of New Mexico, and the western-most part of Texas. Generating capacity margins during summer peak range between 27% and 8% for the next ten years.

The Arizona-New Mexico Power Area utilities continue to forecast generating capacity levels greater than their targeted reserve margins into the mid-1990s. Due to the surplus of resources, emphasis on marketing of generating capacity to utilities in adjacent WSCC areas has become increasingly important to the economic health of area utilities. Also, the Region's load and resource mix combined with localized surpluses of baseload capacity, de-escalating fuel price differentials, and a trend towards more efficient operation on a regional scale make surplus energy transfers to adjoining areas an economic necessity.

Relatively few cogeneration and small power production facilities continue to be forecast. This is due to significant baseload coal-fired and nuclear generation within the Area, resulting in an overall low avoided cost for such electricity producers.

There is uncertainty regarding load forecasts, with many of the Area's utilities planning to meet a significant portion of their future load requirements through demand management and energy conservation programs. Concern regarding the amount of load that can be managed is not as prominent as in the past, due principally to the emergence of contingency planning by some utilities. In addition, power plant life extension programs for existing plants are being initiated to postpone unit retirements and the need for new generating capacity.

The Arizona to California transmission system has been strengthened through the years and no major transmission issues appear eminent within the Area. Similarly, with the planned phase-shifting transformer additions in Colorado and Utah, the Four Corners transmission system to the West should experience some relief from high transmission loading levels which have been encountered on a near continual basis. Although relief from stressed transmission loading conditions is expected, economic pressures to maintain high transfer levels will continue.

The continued expansion of remedial action schemes by Pacific Northwest and California utilities is a continuing

concern due to the serious impact on Arizona-New Mexico systems should the schemes fail. The Arizona-New Mexico utilities are actively working with the California utilities, both directly and through WSCC, to increase the assurance that present and proposed remedial action schemes will operate as planned and not inadvertently degrade system reliability.

In conjunction with the completion of the third Palo Verde nuclear unit, seasonal shutdown of some of the Area's gas-, oil-, and coal-fired generating units is continuing. Area utilities are coordinating these generating unit shutdown programs to insure that inadvertent capacity shortages are not created during off-peak seasons.

California-Southern Nevada Power Area

The California-Southern Nevada Power Area encompasses most of California, southern Nevada, and the northern portion of Baja California, Mexico. Generating capacity margins during summer peak range between 28% and 21% for the next ten years.

Non-utility generation additions account for almost 7% of the existing generation in the Area. It is projected that NUGs will provide 42% of the generation resource additions for this Area over the next ten years. Nearly all of the NUGs are located within the service territory boundaries of Southern California Edison Company and Pacific Gas and Electric Company. The availability of existing NUGs, especially cogeneration facilities with capacity factors in the 80-95% range, has demonstrated that most of these units are dependable.

The use of nomograms and remedial action schemes has made increased utilization of the transmission system possible and maximized simultaneous electricity transfers among several areas while assuring stable system operation. Their use has significantly increased within the WSCC Region and, particularly, in the California-Southern Nevada Area. The use of nomograms and remedial action schemes as a means of managing system reliability is becoming a standard operating practice by utilities in this Area. The use of complex nomograms and remedial action schemes requires a high degree of reliability as system integrity is often contingent on their successful operation.

Several transmission projects, three of which are described below, are planned within the Area to strengthen the system and enhance reliability:

- Licensing activities began early in 1985 to construct the Devers-Palo Verde No. 2 500 kV line for operation in 1990. In late 1988, after three and one-half years, the project was conditionally approved by the California Public Utility Commission. It is now planned for operation in 1993. If conditions permitting construction of the line are met and the line is built, it will significantly strengthen the Arizona to California transmission system and improve reliability of the overall WSCC system.

- Tentative 500 kV transmission projects are being planned which will interconnect systems in Idaho, Nevada, Utah, and California. The projects consist of one 500 kV line emanating to the south from the Midpoint area in Idaho to Steptoe in east-central Nevada. Two 500 kV lines will be constructed from Steptoe to the Las Vegas area and one 500 kV line will extend from Steptoe to west-central Utah. The projects are being contemplated for the 1993-95 period.

- The Red Butte-Harry Allen 345 kV line is planned for operation in 1990. The line will serve electricity requirements in southern Nevada and will provide a strong system interconnection between Utah and southern Nevada.

It is clear that the evolving issues associated with deregulation, transmission service, economy versus reliability, and increasing competition will pose numerous challenges for the WSCC member systems in day-to-day system operation and in planning a reliable and affordable electric system for the future. The members of WSCC, through their continuing coordination activities with utility organizations, non-utility organizations, the regulatory community and others, are intent upon responsibly meeting these challenges to provide a reliable and affordable electricity supply for customers within the WSCC Region.

Western Systems Coordinating Council (WSCC), with 62 member systems and three affiliates, encompasses approximately 1.8 million square miles of territory in 14 western states, two Canadian provinces, and the northern portion of Baja California, Mexico. The Region is characterized by extremes in population and load densities in addition to long distances between load centers and electric generation sources. The Region is subdivided into four areas, namely: the Northwest Power Pool Area, which is winter peaking and heavily dependent on hydroelectric generation; the Rocky Mountain Power Area, which is either summer or winter peaking with a 24% hydroelectric and 60% coal-fired generating capacity mix; the Arizona-New Mexico Power Area, which is summer peaking with a 22% gas- and oil-fired and 46% coal-fired generating capacity mix; and the California-Southern Nevada Power Area, which is summer peaking and heavily dependent on gas-and oil-fired generating units.

RELIABILITY ASSESSMENT SUBCOMMITTEE

JOHN H. STOUT (ERCOT)
Subcommittee Chairman
Manager of Engineering Design and Development
Houston Lighting & Power Company

CHISNA H. FLEMING (ECAR)
Subcommittee Vice Chairman
Manager, Advanced Engineering and Planning
Ohio Edison Company

H. KENT SAATHOFF (ERCOT)
Principal Engineer
Electric Reliability Council of Texas

SAMUEL C. THOMAS (MAAC)
Director, Transmission Planning & Analysis
GPU Service Corporation

JOHN F. WATSON (MAIN)
Manager, System Planning
Union Electric Company

LEON R. BARRETT (MAPP)
Director, Transmission and Inter-Utility Planning
Northern States Power Company

EDWARD A. SCHWERDT (NPCC)
Engineering Manager
Northeast Power Coordinating Council

STEPHEN G. WHITLEY (SERC)
Manager of Power Supply
Tennessee Valley Authority

MARTIN S. KLOTZBACH (SPP)
Manager, System Planning
The Kansas Power and Light Company

ROBERT L. DINTELMAN (WSCC)
Assistant Administrative Manager
Western Systems Coordinating Council

E. ARTHUR MARRIAGE
Canada Member-at-Large
Director of System Planning
Ontario Hydro

JAMES E. BRABSTON, JR.
NERC Operating Committee Representative
Vice President-Bulk Power Management
Entergy Services, Inc.

ARTHUR R. GARFIELD
NERC Operating Committee Representative
Manager, System Operations
Ohio Edison Company

VIRGINIA C. SULZBERGER
Subcommittee Staff Coordinator
Director-Engineering
North Amercian Electric Reliability Council

NERC "1989 Reliability Assessment" Questionnaire

Your input is requested to help us improve the quality and readability of this annual Reliability Assessment report. Please complete the following and return to the NERC office (See address on other side).

A. *Type of organization (check one):*

- ☐ Electric Utility
- ☐ Manufacturer, Utility Products
- ☐ Manufacturer, Other
- ☐ Architect/Engineer/Consultant
- ☐ Financial Institution
- ☐ Research & Development
- ☐ Library
- ☐ University
- ☐ Press/Media
- ☐ Congress (U.S.)
- ☐ Fed. Energy Regulatory Com.
- ☐ Department of Energy (U.S.)
- ☐ Other Fed. Organization (U.S.)
- ☐ State Government
- ☐ State Utility Commission
- ☐ General Public
- ☐ Federal Parliament (Canada)
- ☐ National Energy Board (Canada)
- ☐ Other Fed. Organization (Canada)
- ☐ Provincial Goverment (Canada)
- ☐ Ministry of Energy (Provincial)
- ☐ Energy Board (Provincial)
- ☐ Other (specify): _____

B. *Please indicate your State/Province:* _____

C. *Indicate all portions of the report read or reviewed and comment appropriately (check all items that apply):*

	Read All	Read Partially	Not Read	Very Good	Good	Fair	Poor	Comments
Executive Summary	☐	☐	☐	☐	☐	☐	☐	
Front Chapters								
Reliability/Customer	☐	☐	☐	☐	☐	☐	☐	
Peak Demand Projections	☐	☐	☐	☐	☐	☐	☐	
Generation Reliability Assessment	☐	☐	☐	☐	☐	☐	☐	
Transmission Reliability Assessment	☐	☐	☐	☐	☐	☐	☐	
Reliability Issues								
Demand Exceeding Forecast	☐	☐	☐	☐	☐	☐	☐	
Economy versus Reliability	☐	☐	☐	☐	☐	☐	☐	
Public Policy Disincentives	☐	☐	☐	☐	☐	☐	☐	
Transmission Service & Deregulation	☐	☐	☐	☐	☐	☐	☐	
Environmental Considerations	☐	☐	☐	☐	☐	☐	☐	
Non-Utility Generation	☐	☐	☐	☐	☐	☐	☐	
Regional Assessments								
Introduction	☐	☐	☐	☐	☐	☐	☐	
ECAR	☐	☐	☐	☐	☐	☐	☐	
ERCOT	☐	☐	☐	☐	☐	☐	☐	
MAAC	☐	☐	☐	☐	☐	☐	☐	
MAIN	☐	☐	☐	☐	☐	☐	☐	
MAPP	☐	☐	☐	☐	☐	☐	☐	
NPCC	☐	☐	☐	☐	☐	☐	☐	
SERC	☐	☐	☐	☐	☐	☐	☐	
SPP	☐	☐	☐	☐	☐	☐	☐	
WSCC	☐	☐	☐	☐	☐	☐	☐	

Length of Report	☐	Too Long	☐	OK	☐	Too Short	
Number of Tables	☐	**Too Many**	☐	**OK**	☐	**Not Enough**	
Number of Figures (Graphs)	☐	Too Many	☐	OK	☐	Not Enough	
Depth and Detail of Report	☐	**Too Much**	☐	**OK**	☐	**Not Enough**	

	Very Good	Good	Fair	Poor	
D. *Total Report (Overall Impression)*	☐	☐	☐	☐	

(Over Please...)

NERC "1989 Reliability Assessment" Questionnaire (continued)

E. *General Comments:*

Portions of the report you would like to see improved/enhanced: _____

_____

_____

Portions of the report you did not find useful: _____

_____

_____

Please comment on the usefulness of the tables, figures, and (blue) sidebars: _____

_____

_____

Any reliability issues that were not included that should be addressed: _____

_____

_____

Other comments: _____

(fold here)

_____

_____

_____

(fold here)

Name and Address (Optional):

Name _____

Title _____

Organization _____

Street _____

City _____ State/Province _____

Country _____ Postal/Zip Code _____

Place Stamp Here

North American Electric Reliability Council
101 College Road East
Princeton, New Jersey 08540-6601

(fold into thirds and tape here)

North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

AFFILIATE

ASCC
Alaska Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers).

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

North American
Electric
Reliability
Council

101 COLLEGE ROAD EAST
PRINCETON, NEW JERSEY 08540-6601

609-452-8060